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A Database and Workflow Integration Methodology for Rapid Evaluation and Selection of Improved Oil Recovery (IOR) Technologies for Heavy Oil Fields

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ABSTRACT

Conventional crude oil, as the current dominant energy source, is an unrenewable resource. Despite the improvement of alternative energy technology such as wind and solar, there is still a large gap between the capability of these systems for supplying energy and global energy requirements. Therefore, until technological innovations facilitate sufficient energy generation through alternative fuels, other means of sustaining crude oil production such as improved oil recovery methods (IOR) could be utilised. In addition to increasing production of conventional oil, IOR methods have the potential to extract oil from unconventional reservoirs such as heavy oil fields. This capability is of importance due to the large size of global heavy oil reserves.

There are several IOR technologies available and each of them is suitable for a certain type of oil field. The aim of this paper is to suggest an alternative low cost and quick screening method to the more technical and costly methods for selecting the most suitable technology for heavy oil extraction project utilising a limited range of data.

After reviewing the mostly applied IOR methods and available empirical reservoir modelling correlations, it was concluded that a two-stage screening method, the first one based on literature data of previous projects and the second one based on the simple empirical oil production methods such as Marx and Langenheim model coupled with Ingen's RAVE (Risk and Value Engineering) and Schlumberger's PIPESIM, could give reasonable results and eliminate the unsuitable methods effectively with minimum cost and time during the preliminary stages of a project. This effectiveness was tested via a comprehensive case study.

1. INTRODUCTION

As societies have become more prosperous, the demand for energy and consequently oil has been increased. However, as the light oil reserves become depleted and matured, other energy resources should replace them in order to maintain the energy price at reasonable values. Considering the potential of current technologies available for energy generation such as wind and tidal, other fossil fuels such as bitumen and heavy oil which are currently not as cost efficient as light oil are still the primary source which can fulfil the high global energy requirements. Despite the lower depth of heavy oil reservoirs compared to conventional oil ones, heavy oil is normally not capable of flowing naturally from reservoir to the surface due to low reservoir pressure, high viscosity and density of them, as illustrated in Table 1 (Farough, 2002; Freeman, 2007; Speight, 2013), and some form of assistance is required in order to facilitate this process. These methods in general are called improved oil recovery methods (IOR).

Table 1: Properties of conventional oil compared to heavy oil and bitumen

Identity	Unit	Conventional Oil	Heavy Oil	Bitumen
API Gravity	Degree	38.1	16.3	5.4
Depth	m	1,567	991	373
Viscosity (25 ◦C)	cP	13.7	100,947	1,290,254
Viscosity (55 ◦C)	cP	15.7	278.3	2,371
Asphalt	wt%	8.9	38.8	67
Asphaltenes	wt%	2.5	12.7	26.1
Carbon	wt%	85.3	85.1	82.1
Nitrogen	wt%	0.1	0.4	0.6
Oxygen	wt%	1.2	1.6	2.5
Sulphur	wt%	0.4	2.9	4.4
Flash Point	◦C	-8	21	-
Pour Point	◦C	-8	-6	23
Aluminum	ppm	1.174	236.021	21,040.03
Iron	ppm	6.443	371.05	4292.96
Nickel	ppm	8.023	59.106	89.137
Lead		0.933	1.159	4.758

Since production of heavy oil through IOR is cost intensive due to the requirement of extra CAPEX and OPEX, their utilisation is heavily dependent on the price of oil in the market. Since, eventually, higher oil prices are expected due to reduction in easily obtainable oil, cost evaluation of IOR projects in early stages is essential for reducing the risks associated with them. Therefore, acquiring the software and tools that can evaluate the techno- economic aspects of IOR and heavy oil projects rapidly and accurately at the early stages can give oil producing companies an advantage over the competitors.

In this paper, initially, the concept of IOR technologies and the purpose of their applications are briefly explained and the technologies are categorised. Then, within the sections 2 and 3, the feasibility of different IOR methods is checked by benchmarking the oil field properties against the previous and current IOR projects by using a comprehensive data base generated during this study. Afterwards, in sections 4 and 5, the techno-economic aspects of the IOR methods are analysed and tested through a theoretical case study in order to select the one with the highest possible profit margin. These simulations are carried out by PIPESIM (Schlumberger, 2011), empirical pressure and heat loss calculation correlations along with Ingen's techno-economic analyser tool RAVE (Ingen-Ideas, 2010). By doing so, it can be concluded if a quick and low cost prediction of the optimal IOR technology and the oil production rate of that respective technology could be made.

1.1 What is IOR?

Improved oil recovery methods or IOR are the methods applied in order to facilitate or increase oil flow rate from the well. IOR methods can be sub-categorised into two main groups of secondary and tertiary. Tertiary methods are also referred to as enhanced oil recovery methods (EOR).

During the application of the secondary methods, no alterations are done on oil properties. The main objective of them therefore is to either maintain the reservoir pressure or increase the pressure gradient between well bottomhole pressure and head pressure. In other words, they can be applied at the start of a project in order to maintain the pressure of the reservoir or can be applied sometime after the production has started to increase the production rate. EOR methods themselves can be sub categorised into three main groups of cold (gas), chemical and thermal based methods. Unlike the secondary methods, tertiary methods alter the properties of the oil in the reservoir to enhance the flow. Similar to secondary methods, EOR methods can also be applied at different stages of the project. However, due to the high cost of their operation, they are normally applied for recovery of heavy oil or the incremental oil which has remained in the reservoir after application of primary and secondary recovery methods.

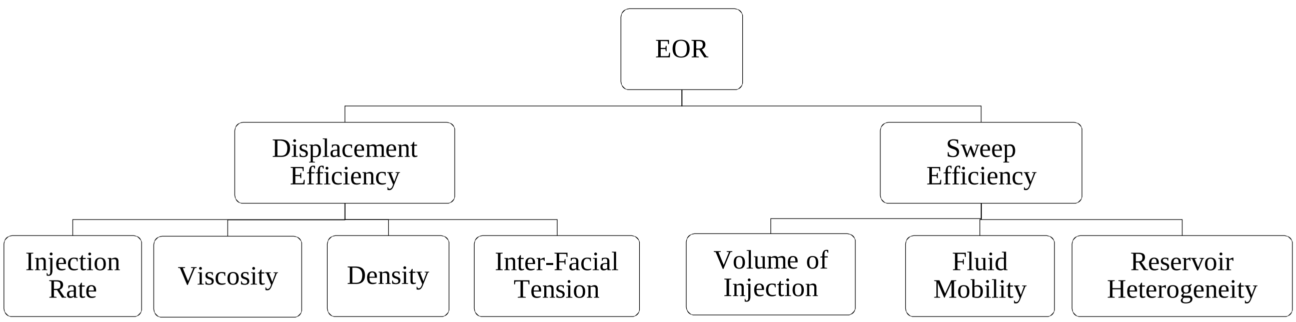


Fig. 1. Main parameters affecting oil recovery through EOR methods

Illustrated in Figure 1, displacement efficiency and sweep efficiency are the main mechanisms by which oil recovery is improved through EOR applications. In addition, Figure 2 illustrates the parameters by which the oil recovery is enhanced by application of each EOR method. Also, all of the IOR methods which were reviewed and compared in this study are listed in Figure 3.

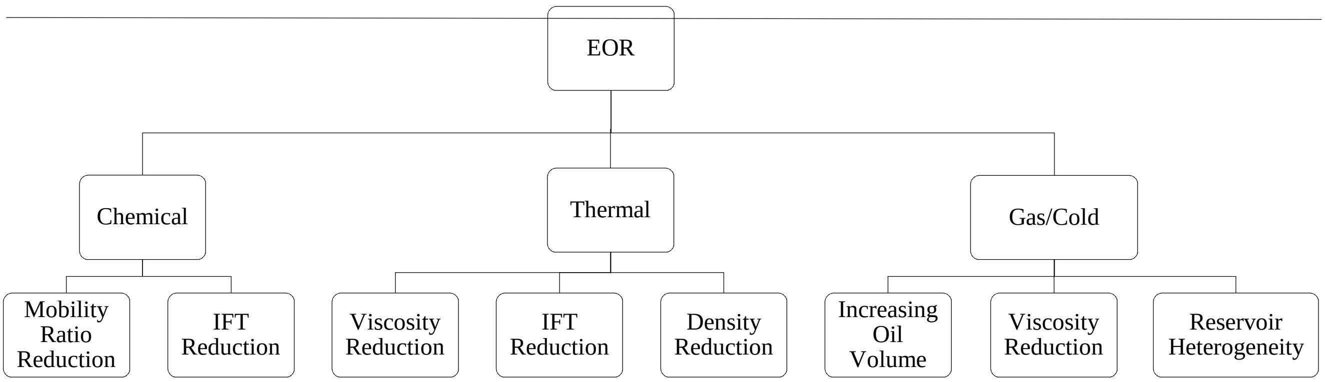


Fig. 2. Main effects of each EOR category

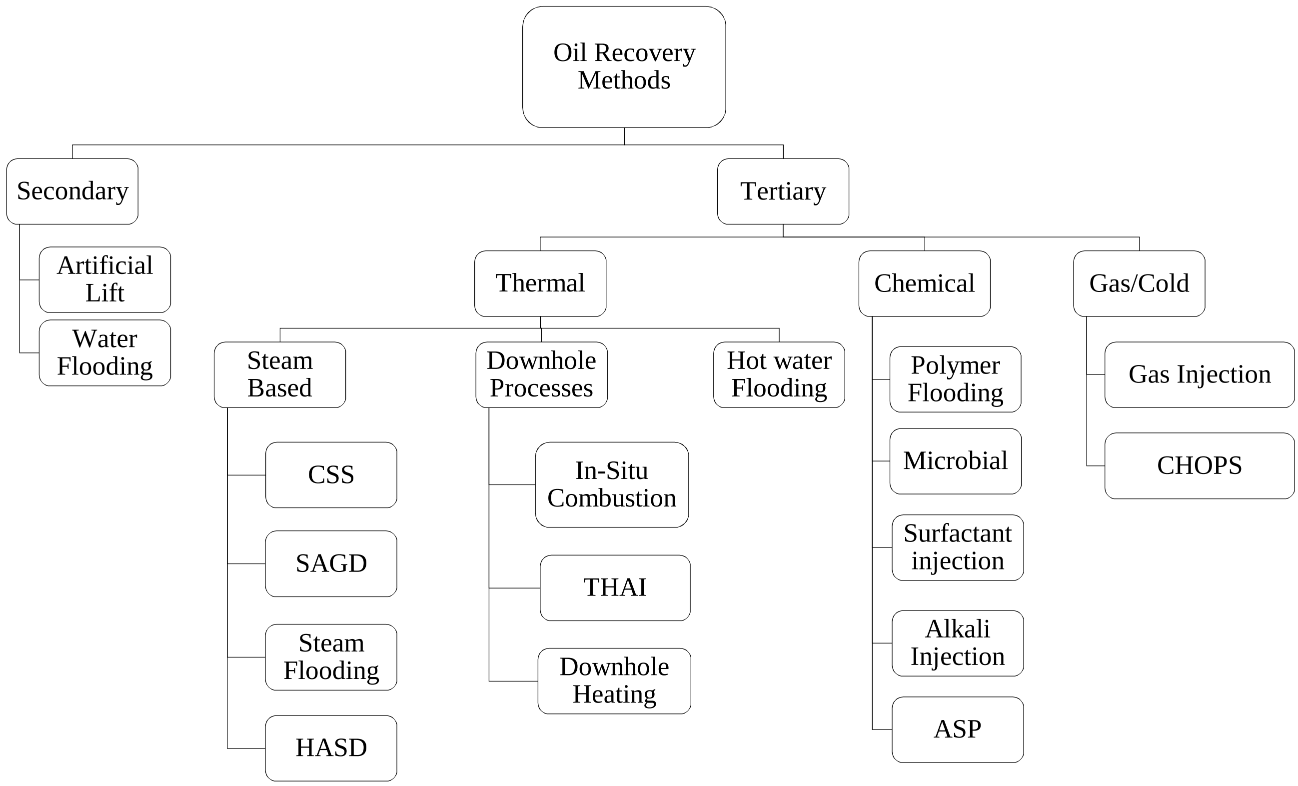


Fig. 3. List and categorization of IOR methods

2. ARTIFICIAL LIFT

Artificial lift is a component which is installed in production wells in order to either increase or maintain the flow rate of the fluid. As illustrated in Figure 4, artificial lift can be grouped into two general categories of pump-based and fluid- based. The main objective of pump-based artificial lift is to increase the pressure of well fluid by use of external forces. On the other hand, fluid-based artificial lift increases the flow rate through expanding the fluid which consequently reduces the hydrostatic head in the well and facilitates higher flow rates.

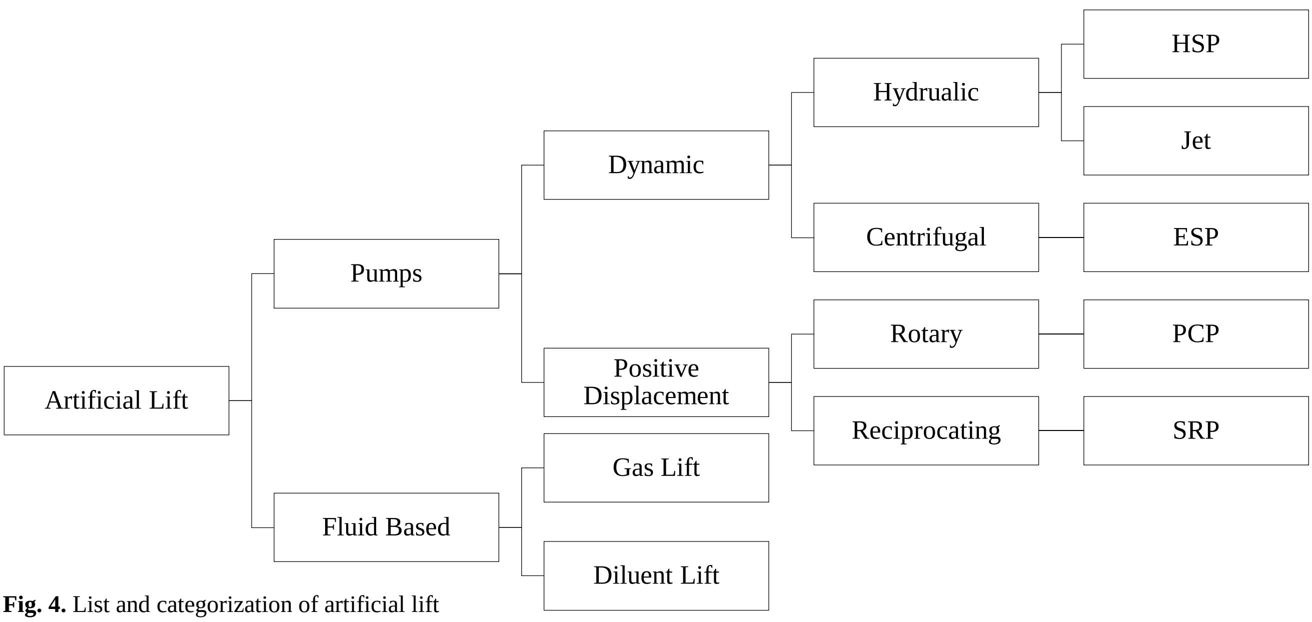


Fig. 4. List and categorization of artificial lift

2.1 Artificial lift comparison and selection

The suitability of a particular artificial lift method is strongly dependant on the reservoir conditions and oil properties. Some of the parameters that can affect the selection procedure are listed below:

- Reservoir depth
- Production capacity
- Operating temperature
- Oil API gravity and viscosity
- Solid and gas content of produced fluid
- Deviation of the well
- Location of the field

Each artificial lift method has operational limits based on one or more of the parameters listed above. For instance, SRP pumps are limited to the fields located onshore and cannot be installed offshore. Therefore, before analysing the performance of the methods under production conditions, their applicability to the respective well should be verified.

The applicability boundaries of the pumps based on the commercial artificial lift operations and industrial norms is collected and shown in Table 2 (Cuesta, 2013; Ingen, 2002; James, 1999) which can be used as a data base to check the operability of methods.

Table 2. Operating ranges and limits of artificial lift methods

Parameter	Unit	AMPCP	ESP	Jet Pump	HSP	Gas Lift	SRP
Minimum depth	ft	2000	1000	5000	2000	5000	100
Maximum depth	ft	7500	16000	15000	20000	15000	14000
Minimum capacity	BPD	5	150	300	50	100	50
Maximum capacity	BPD	5000	60000	35000	60000	50000	7000
Maximum Temperature	ºF	450	400	500	500	400	500
API gravity	º	< 35	> 10	> 8	> 8	> 15	> 8
Viscosity	cP	-	< 400	< 800	< 800	< 1000	< 500
GOR	$SCF.STB^{-1}$	-	< 2000	< 2000	< 2000	-	< 2000
Sand content	%	-	< 0.01	< 3	< 0.01	-	< 0.1
Wellbore deviation	º	< 80	< 80	-	-	< 70	< 50

After applicability approval, the performance of the suitable methods should be compared to eliminate the less appropriate ones. Some of the important parameters and operational issues affecting the performance of artificial lift and consequently the elimination procedures are listed below:

- Energy efficiency
- Corrosion probability
- Emulsion formation
- Foam formation
- Asphaltenes existence
- Maintenance procedure
- Paraffin existence

Energy efficiency of each method is also subject to fluctuation under production conditions. However, based on the data found in numerous sources, a range of energy efficiencies can be expected from each method. Figure 5 illustrates this expected range for each method alongside the value observed the most in industry (Aliyev, 2013; Lift, 2014; Nguyen, 2007).

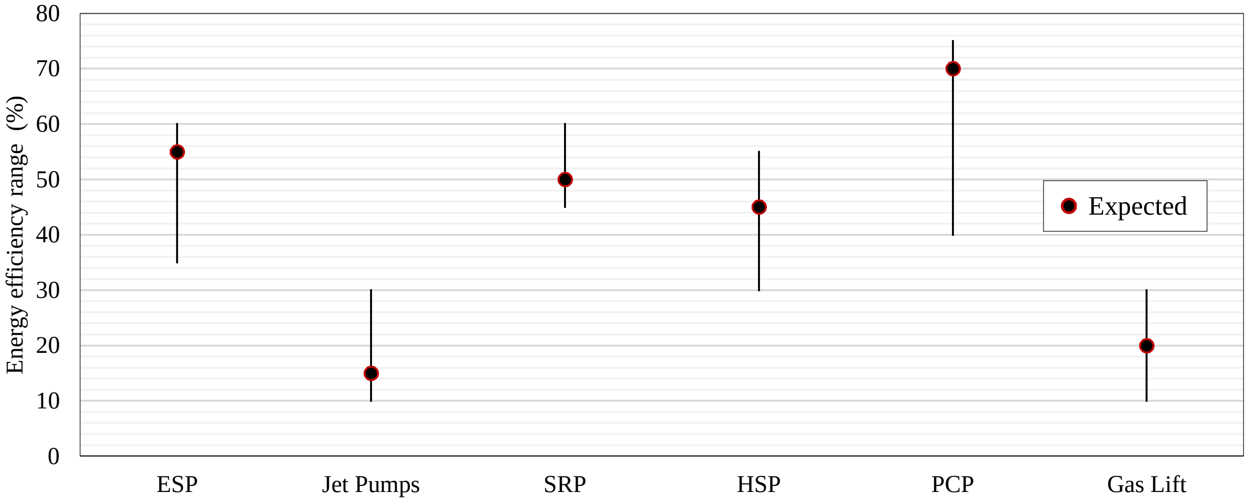


Fig. 5. Energy efficiency range of artificial lift methods

To compare artificial lift methods qualitatively and based on their capability to handle operational issues, their performances are ranked from 1 to 5 in Table 3 (Aliyev, 2013; Ehsan Fatahi, 2011; Ingen, 2012; Prasanna Mali, 2014). According to this ranking, the higher the number, the more the performance is affected by the associated operational issue. Since the data in the sources from which the information is obtained are not consistent, the values most cited have been selected. This inconsistency in data is also observed for the data tabulated in Table 2. In that case, the highest and lowest values have been selected to prevent premature and unnecessary elimination of methods.

Table 3. Artificial lift operational issues ranking

Operational Issue	AMPCP	ESP	Jet Pump	HSP	Gas Lift	SRP
Corrosion	1	3	1	2	2	3
Emulsion	1	4	3	3	2	3
Foam	1	2	2	2	1	2
Asphaltenes	1	4	2	3	3	3
Paraffin	3	2	2	2	2	3
Solids	1	4	3	3	2	3

In order to check the applicability of artificial lift methods with respect to reservoir conditions as accurately as possible at conceptual level, the appropriateness of the operating conditions of each method must be checked against these parameters simultaneously. To aid this, an Excel-based tool has been produced which compares the methods qualitatively and quantitatively based on the reservoir and production data input.

3. IOR METHODS SCREENING, COMPARISON AND SELECTION

The fundamental property that should be considered during the screening procedure is the type of the formation rock. In 2004 almost 80% of all the IOR method had been applied in sandstone reservoirs (Manrique, 2010). Additionally, despite the dominancy of thermal methods in sandstone reservoirs, they hold the lowest share of projects in carbonate reservoirs. The main reason for the lack of application of thermal methods in carbonate reservoirs is the rapid heat loss to overburden and under burden rocks (Speight, 2009).

Another crucial factor in the selection of IOR methods is the reservoir depth. However, in the case of heavy oil, depth of reservoir should be correlated with the viscosity of it due to the difficulty of the flow as the depth is increased. For instance,

thermal methods are capable of handling high viscosities at low depths. On the other hand, gas injection methods are the most suitable choice for deep reservoirs such as offshore fields (Kokal, 2011; Rivas, 2013; Wassmuth, 2009).
With the exception of thermal methods, IOR methods applicability for heavy oil projects have not been proven. Therefore, in order to simplify the comparison stage, the methods unsuitable for heavy oil extraction were eliminated based on the API gravity and viscosity of the oil fields that these IOR methods were applied to up to this date. In addition to the methods with limited capability in producing heavy oils, some of the methods which are capable of producing heavy oil but have limited success based on previous projects were also eliminated. For instance, in-situ combustion was eliminated due to the fact that after 60 years of development, it is only commercially applied in USA with high capital and operational cost (Law, 2012).

After the elimination stage, the following methods were shortlisted for quantitative comparison:

- Steam based methods
- Hot water flooding (HWF)
- Polymer flooding
- Alkali-Surfactant-Polymer (ASP)
- Miscible and immiscible hydrocarbon gas injection (M HC and IM HC respectively)
- Immiscible nitrogen injection (IM N_2)
- Immiscible CO_2 injection (IM CO_2)
- Water Flooding (WF)
- Immiscible hydrocarbon WAG (IM WAG)

In addition to the formation type, oil viscosity and reservoir depth, other key parameters should be considered during comparison and screening of IOR methods. Some of these properties are listed below:

- Location of the field
- Natural water drive of the reservoir
- Formation permeability and porosity
- Reservoir thickness
- Reservoir pressure and temperature
- Formation oil saturation

For instance, if the field is located offshore, steam based methods should be eliminated by default due to the excessive heat loss through subsea pipelines. Table 4 which is generated based on several commercial and pilot IOR projects can be utilised as a data base to compare the boundary limits of each of the methods based on several critical criteria (Adasani, 2010; Alvarado, 2002; Christensen, 2001; Kokal, 2010; Koottungal, 2012, 2014; Speight, 2009; Speight, 2013). Two important points should be considered when these boundary data are used. First of all, these values are based on the maximum and minimum values found in project reports and not the common and ideal values. Secondly, similar to artificial lift boundaries, these numbers are subject to change as their technologies are updated in the future. After confirming which IOR methods are technically viable, the key factor affecting the final decision on type of IOR project is the economical aspect of the methods such as CAPEX and OPEX.

In case of recovery factors of each method, as illustrated in Figure 6 (Adasani, 2010; Delamaide, 2014; Fernandez R, 2008; Koottungal, 2012, 2014; Shen, 2013; Speight, 2009), estimations can be made based on the recovery factor of similar projects applying the respective IOR method. Recovery factor has high importance during the selection of the suitable method due to the fact that the additional oil produced by one method could be the decisive factor. Similar to Table 4, some caution should be taken when using the values in Figure 6 because most of the projects in the literature have undergone several IOR methods during the field production life. Therefore, it is probable that the improved oil recovery is not solely the result of the recently applied method.

Table 4. Boundary criteria in selection of IOR methods

Methods	Minimum Permeability	Maximum Permeability	Minimum Porosity	Minimum Depth	Maximum Depth	Reservoir Thickness	Minimum Viscosity	Maximum Viscosity	Reservoir Temperature	Reservoir Pressure	API Gravity	Oil Saturation
	(mD)	(mD)	(%)	(ft)	(ft)	(ft)	(cP)	(cP)	(°F)	(psi)	(°)	(%)
CSS	2000	-	20	1000	3000	>20	300	-	-	<4000	<20	20
SF	100	-	36	500	3000	>10	300	-	-	<4000	<20	20
SAGD	50	-	18	-	5000	>6	50	350000	-	<4000	-	20
HASD	300	-	20	300	4000	>15	140	20000	-	<4000	-	20
HWF	900	6000	25	500	3000	-	170	8000	75-135	-	>10	15
Polymer	2	9000	10	500	9500	<25	0.1	5000	70-240	145-2200	>12	30
ASP	500	9000	16	2000	4800	<25	10	6500	80-180	145-2030	>20	30
IM CO_2	20	1000	15	1200	8500	-	-	600	80-200	-	>11	30
M HC	20	5000	4	300	15900	-	0.1	500	70-330	1280-5000	>20	30
IM HC	20	5000	5	1800	8000	-	-	10	<200	-	>20	75
IM N_2	3	2800	11	1700	18500	-	-	20	80-330	-	>16	45
WF	3	-	15	-	10000	-	-	2000	-	-	>14	20
IM WAG	100	6600	18	2500	9200	-	-	16000	80-270	-	>6	70

Since all of the applicability requirements of IOR methods should be considered simultaneously for minimising the error and time consumption, an Excel based screening tool has been developed which considers all the criteria included in Table 4 in addition to the field location and formation rock type. Also, the recovery factor of suitable methods alongside the typical topside facility requirement of each method can be compared in the tool.

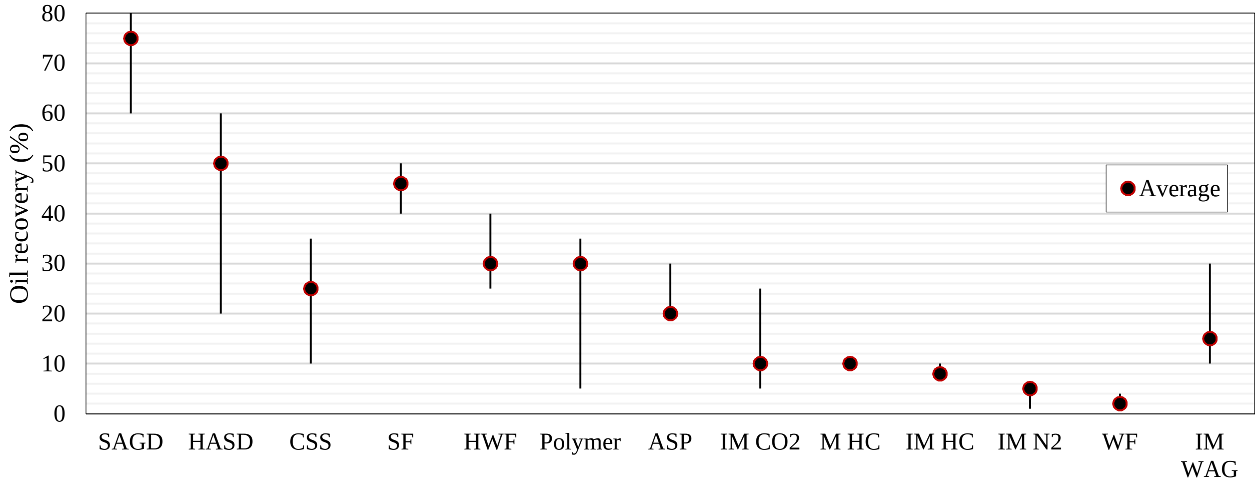


Fig. 6. Recovery factor range of final IOR methods

4. TECHNO-ECONOMIC ANALYSIS

The first step towards modelling and forming a methodology for integrating the IOR methods into simulation software was to eliminate the unsuitable IOR methods. Ideally, the goal was to select at least one method from each IOR category, i.e. one thermal, one chemical and one cold method. However, since the main aim was to keep the costs to a minimum, only the methods which could be simulated via empirical correlations were considered rather than the ones which required more sophisticated reservoir simulation software such as ECLIPSE. In other words, the main objective of this stage was to accelerate the process of screening and techno-economic analysis of IOR methods through generation of an uncomplicated and low-cost workflow.

First of all, application of cold methods was considered. It was decided that only the methods by which the reservoir pressure is maintained could be applied. Therefore miscible gas injection method was deemed unsuitable for integration with complexity of gas dissolution in the reservoir being the main decisive parameter.

Next, thermal IOR methods were considered. SAGD and HASD were eliminated as the result of immaturity of the methods and therefore inability to model the reservoir without availability of project based data. CSS was also eliminated because of inaccuracy in calculation of the latent effect of steam in the reservoir utilising empirical formulas and correlations.

Finally, chemical methods were considered. Since evaluation of the effectiveness and efficiency of chemical methods requires frequent reservoir sample testing in the laboratory and simulation through chemical specific integrated asset models, their modelling at this level was deemed impractical.

The final selected methods, therefore, were shortlisted to:

- Thermal flooding methods; i.e. steam and hot water flooding
- Pressure maintenance methods; i.e. water flooding and immiscible gas injection

Since all of the above methods are flooding-based ones, their simulation requires injection and production well modelling in addition to reservoir modelling. Also, due to the fact that financial aspects of the methods are of great importance during the selection of the most suitable IOR method, they should be integrated into the model.

As the application of IOR methods is sensitive to the additional oil extracted, it was decided to base the methodology for their integration on the maximum possible oil flowrate through production well. By selecting an optimum oil flowrate based on the reservoir conditions at the bottomhole of production well, the cost associated with the method capable of achieving the required oil flowrate can be calculated. Consequently, profitability of different IORs could be examined against each other. The basic four steps towards achieving these objectives are listed below:

1. Obtaining the production profile and selecting the maximum liquid flowrate through production well as the target flowrate
2. Calculation of the required injected fluid for obtaining the target production rate
3. Determination of conditions of injection facilities
4. Evaluation of the economics of each method based on OPEX, CAPEX and oil price

To achieve the above objectives, several software should be used. Therefore, an integrated asset modelling (IAM) tool is required to combine the outcome of these software. Given that the reservoir and wells models are available, RAVE (Risk & Value Engineering), Ingen in-house IAM tool, has the capability to combine the reservoir and well model while considering the economics of the process in a scenario based environment.

RAVE can also estimate the cumulative oil production rate during the life of a project. To do this, RAVE requires the well and production system pressure drop profile or lift tables of the production system. Schlumberger's PIPESIM can be used to model the wells and production flow line to obtain their pressure profile.

Finally, in order to model the reservoir behaviour and evaluate the cost of project, Microsoft Excel could be utilised. To summarise, in total, three separate software were utilised for modelling the selected IOR methods;

- Ingen RAVE (to generate life of field production expectations and associated NPV)
- Schlumberger PIPESIM (to generate ΔP vs. liquid rate of wells and pipeline)
- Microsoft Excel (to simulate reservoir and to calculate pre-modelling OPEX and CAPEX)

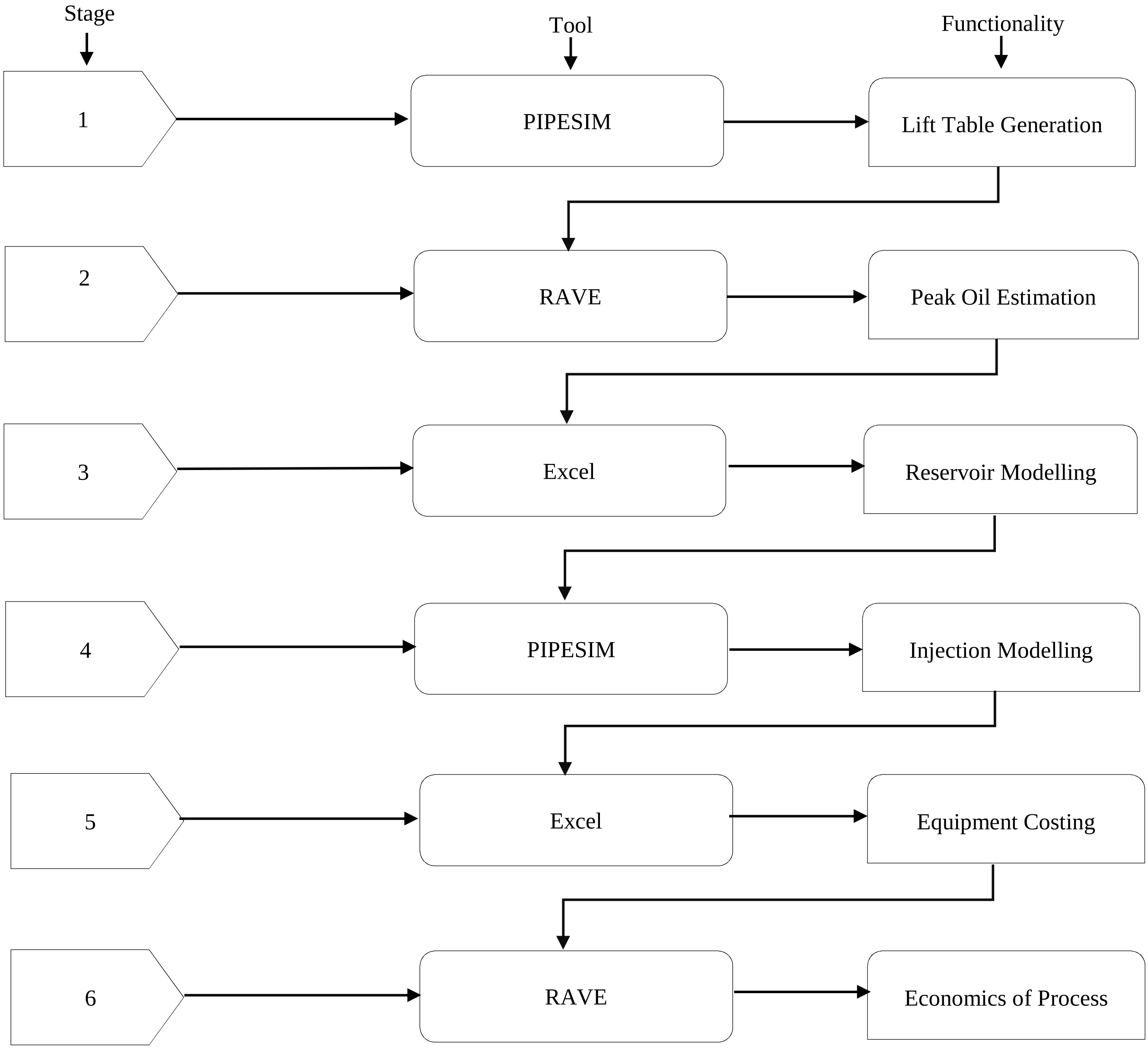
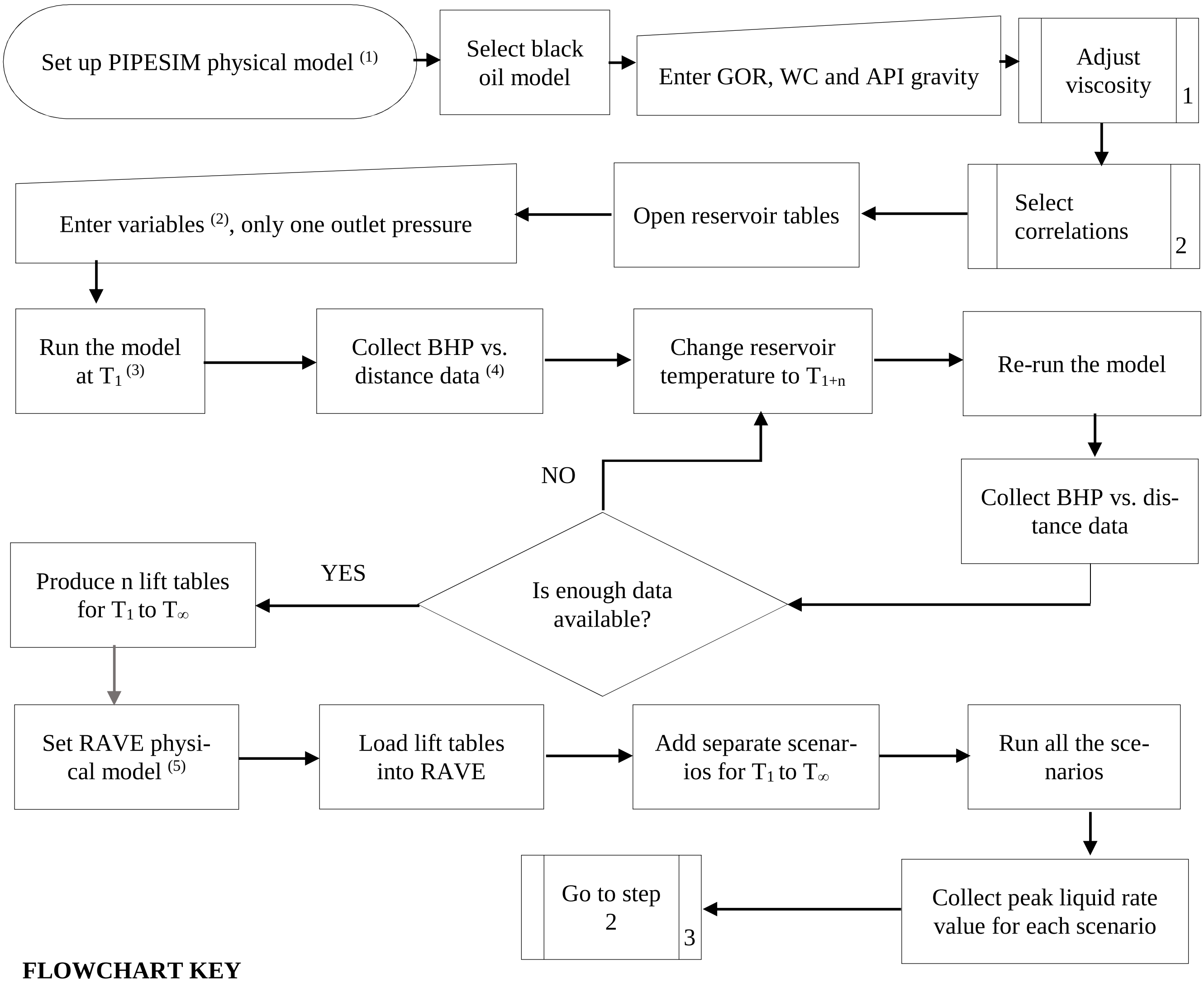


Fig. 7. Software utilised on the integration methodology and their order of utilisation

Figure 7 summarises the order in which each tool is used alongside the functionality of it in the respective stage. It should be noted that that all the data transfers among the three software is carried out manually

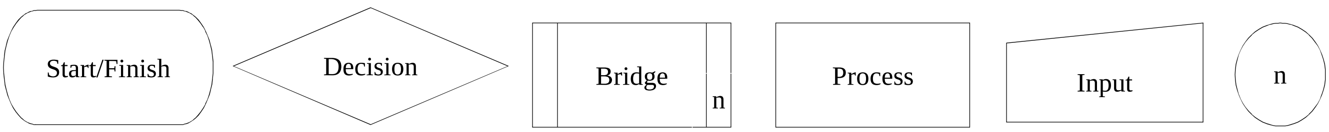
4.1 Thermal flooding methods - Step One; Production System Hydraulic Modelling

The first step towards simulation of IOR methods is calculation of production profile .For simplification of the methodology utilisation, it is presented in form of flowcharts. Figure 8 illustrate the methodology for obtaining the heavy oil thermal flooding lift tables, i.e. pressure drop profile. In addition, Figure 9 includes the procedure for obtaining the maximum oil flow rate through RAVE. Figures 10 and Figure 11 are complementary to Figure 9.



FLOWCHART KEY

Note: n refers to a reference flowchart and circles are bridge connectors



ALGORITHM SPECIFICATIONS

(1) Includes the reservoir, tubing, flowline (variable number), risers and nodes in PIPESIM
(2) Includes the simulation variables such as water cut, gas to oil ratio, liquid flowrate and system outlet pressure
(3) T_1 refers to the reservoir initial temperature. This should be added to the reservoir parameter of the PIPESIM physical model
(4) Since each tubing, flowline and riser requires a lift table, the distance is dependent on the length of each respective parameter
(5) This includes the reservoir, flowline, tubing, riser and host facility. In addition, the economical parameter might be added to the system in cases where economic analysis of the system is required

Fig. 8. Stage one procedure flowchart

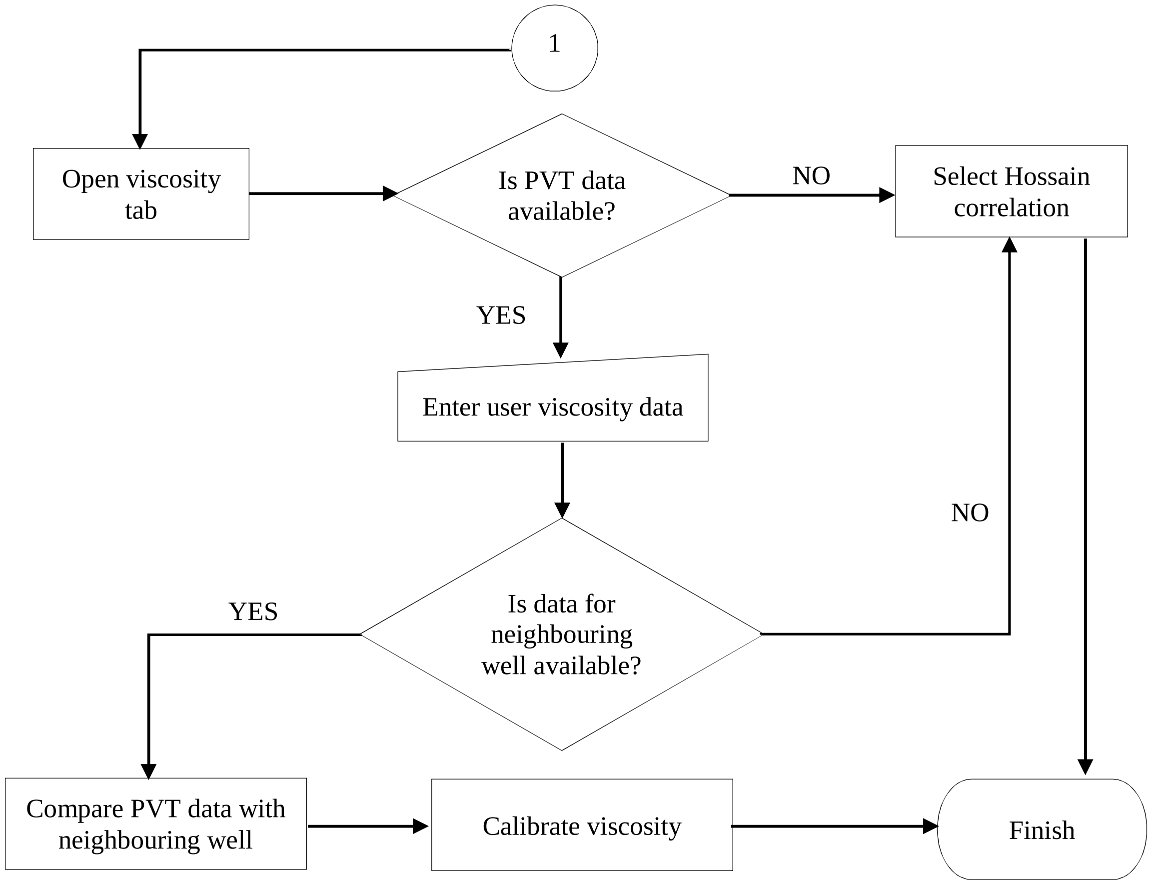


Fig. 9. Viscosity model modification for heavy oil in PIPESIM

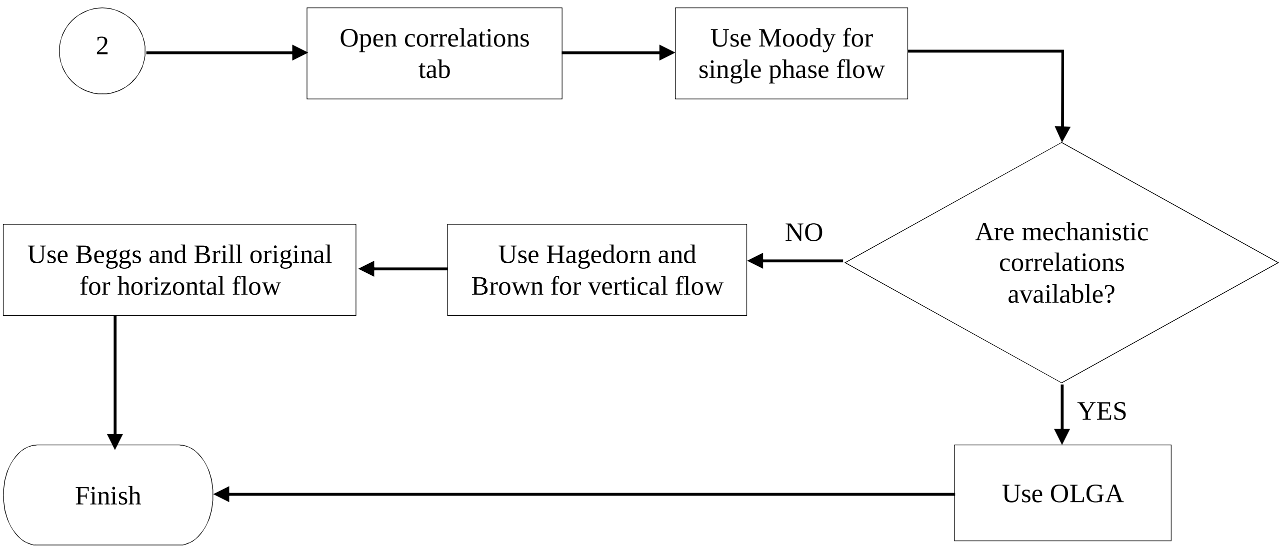


Fig. 10. Correlation assignment for heavy oil pressure drop calculation in PIPESIM

As shown in Figure 9, if the user does not have data for oil viscosity, the Hossain correlation (Eq. (1-3)) could be used. This is due to the fact that Hossain is the only correlation that is solely applicable to heavy oil. In other words, it gives reasonably accurate results for oil with API gravity of between 10 and 22° (Hossain, 2005).

$$\mu_{od} = 10^{A}.T^{B} \tag{1}$$

$$A = -0.71523.API + 22.13766 \tag{2}$$

$$B = 0.269024.API - 8.268047 \tag{3}$$

However, if viscosity data for the specific field are available, Eq. (4-6) should be used in order to calibrate the PIPESIM viscosity correlations for the respective field.

$$log(\mu) = log(B) - Clog(T) \tag{4}$$

$$C = \frac{log\left(\frac{\mu_1}{\mu_2}\right)}{log\left(\frac{T_2}{T_1}\right)} \tag{5}$$

$$B = \mu_1 T_1^C = \mu_2 T_2^C \tag{6}$$

The outcome of this step which is in form of tables is collected and saved as Excel files and is then loaded manually into RAVE.

4.2 Thermal flooding methods - Step Two; Reservoir Resistance

Now, the pressure drop data should be applied in RAVE, the target production flow rate should be achieved and the data should be collected manually as excel files. Also, the required injected fluid flowrate which can facilitate the target production flowrate should be calculated. In other words, the heated fluid flowrate which corresponds to the required temperature at the production well should be obtained. This requires reservoir behaviour and heat loss mechanism analysis. There are several empirical correlations for heat loss calculation in the reservoir which are the basis of more sophisticated tools and are capable of giving reasonably accurate results quickly and at a minimum cost. Four of the most utilised thermal flooding models are:

- Marx and Langenheim (M&L)
- Mandl and Volek (M&V)
- Myhill and Stegemeier (M&S)
- Jones

Among these models, M&L has been used the most as the base for reservoir simulators. Additionally, both M&V and M&S are models attempting to modify M&L. Also, M&L has high reliability and proven record of performance based on previous thermal flooding projects (Sheng, 2013; Speight, 2009). Therefore, it was decided to choose the M&L model for simulation of thermal flooding methods in this paper while including the critical modifications carried out by M&V and Ramsey on it.

Proposed in 1959, the Marx and Langenheim model balances the net heat injected into the reservoir, net heat loss in the formation and heat loss to the reservoir rocks while excluding the heat loss to the cold oil zone in front of steam. M&L model has the following assumptions integrated within it (Jones, 1981; Marx, 1959; Shen, 2013; Speight, 2009; Wang, 1986):

- Constant fluid injection rate
- Fixed injected fluid conditions including pressure, temperature and quality in the case of steam
- Uniform vertical temperature distribution in the reservoir
- No separation between steam and condensate by gravitational affects
- Constant reservoir properties
- Ideal step function between hot and cold zones in the reservoir
- Instant thermal equilibrium in the reservoir

The first step towards reservoir simulation by the M&L model is defining the injected fluid conditions and flowrate. Afterwards, the constant hourly heat content of the injected fluid is obtained by;

$$Q = h_{hf}.M_{hf} \tag{7}$$

Based on the step function assumption, the temperature difference between injected fluid and reservoir is constant and calculated by;

$$\Delta T = T_{hf} - T_r \tag{8}$$

Afterwards, the constant heat capacity of the overburden and under-burden rocks is obtained by;

$$C = (1-\phi)\rho_r c_r + S_w \phi \rho_w c_w + S_o \phi \rho_o c_o \tag{9}$$

In order to obtain the area covered and the volume of oil produced, the time passed from initiation of production should be considered. Marx and Langenheim introduced the dimensionless time function in order to consider this significant factor which is obtained from;

$$x = \frac{2k\sqrt{t}}{CH\sqrt{D}} \tag{10}$$

The area of reservoir swept during time t is obtained by;

$$A(t) = \left[\frac{QCHD}{4k^2\Delta T}\right]\left(e^{x^2} erfc(x) + \frac{2x}{\sqrt{\pi}} - 1\right) \tag{11}$$

Consequently, the volume of oil displaced after t hours of production can be calculated by;

$$V_o = 4.237\left[\frac{Q\emptyset(S_o - S_{or})}{C\Delta T}\right]\left(e^{x^2} erfc(x)\right) \tag{12}$$

The numerical values of error functions embedded in Eq. (11) and Eq. (12) can be found in (Marx, 1959). Finally, the heat loss percentage to the reservoir rock during the injection period can be calculated by using Eq. (13) and Eq. (14) respectively.

$$x^2 = \frac{4Dt}{H^2} \tag{13}$$

$$Q_L = 1 - \frac{1}{x^2}\left(e^{x^2} erfc(x) + \frac{2x}{\pi} - 1\right) \tag{14}$$

Since the M&L model only considers the heat loss mechanism in the reservoir and does not incorporate the injection and production wells, it cannot be used on its own for steam flooding simulation. Due to the fact that the main drawback of M&L is inaccuracy in prediction of maximum oil flowrate through the production well (Marx, 1959; Sheng, 2013), the back-

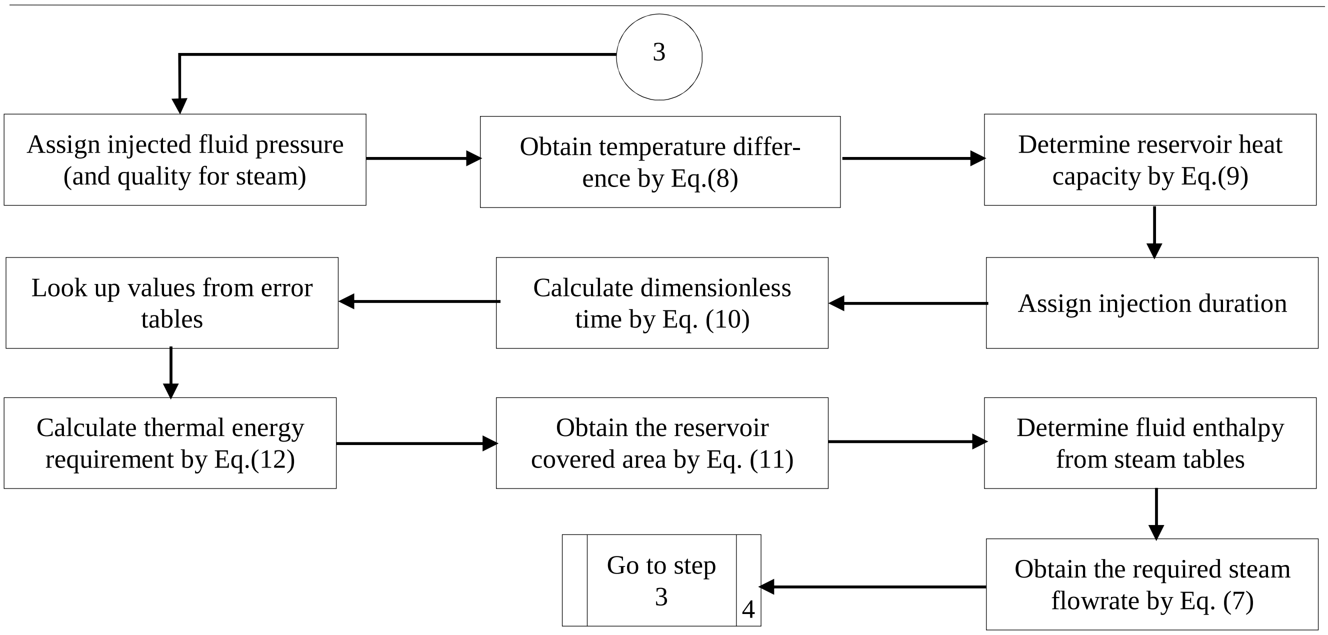
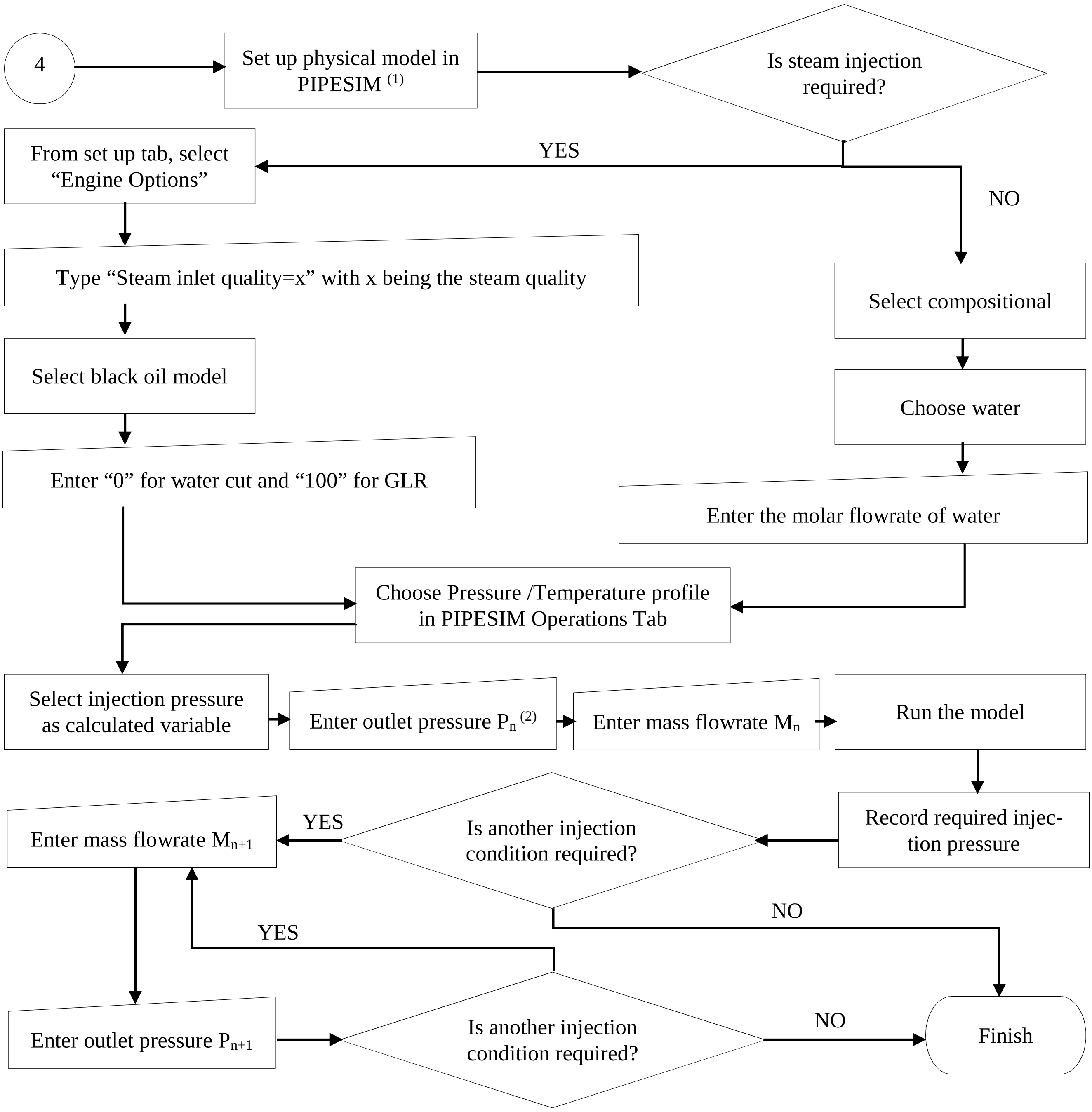


Fig. 11. Flowchart for application of step 2 of methodology

calculation methodology has been selected. This way, the maximum production flowrate is estimated more accurately via PIPESIM utilising the production well bottomhole pressure. Figure 11 is the flowchart representing a summary of the procedure to obtain the injection flow rate from the maximum production flowrate computed in step 1.

4.3 Thermal flooding methods - Step 3; injection well and topside requirement

The steam rate calculated in step 2 is based on the steam conditions required at the bottomhole of injection well. However, the design of topside facilities should be based on the steam properties prior to injection.



ALGORITHM SPECIFICATION

(1) Includes a source, a tubing and flowline (variable numbers)
(2) The required pressure at the bottomhole of injection well

Fig. 12. Step 3 simulation flow chart

In other words, the pressure drop and heat loss in the tubing during the injection should be considered. Similar to step 1, the software used for simulation of injection well is PIPESIM. As shown in Figure 12, there is a slight difference between the steam flooding and hot water flooding in the step 3 procedure.

4.4 Thermal flooding methods - Step 4: economical evaluation

Costing of thermal flooding methods is almost identical to conventional oil extraction methods with the exception of some extra parameters required for heating processes. A simple costing procedure which is only sufficient for elementary screening and comparison of the methods has been carried out.

The first step towards the economic analysis of thermal flooding methods is the evaluation of their operating and capital cost. Since the proposed methodology is based on a fixed injection rate, constant OPEX can be assumed. The most important parameters of thermal flooding OPEX can be summarised in terms of the following:

- Boiler or heater feed water requirement
- Water pumps electricity requirement
- Water treatment processes
- Boiler/heater fuel consumption
- Transportation

Ideally, these costs should be supplied by the project owners based on the vendor quotes or experience from previous projects carried out by the company. This is due to the high area, technology and project dependency of some of these parameters, such as water treatment. However, if these data are not available, some of the parameters necessary for continuous injection, i.e. cost of fuel, electricity and water can be estimated. These estimations can be done based on the amount of thermal energy and consequently mass of steam or water required. After calculating the OPEX of the project, capital cost of the project should be estimated. The main parameters of CAPEX for thermal flooding methods are the cost of:

- Injection and production well drilling
- Boiler or heater
- Pumps
- Fuel and water storage facilities
- Water treatment facilities

Since well drilling cost is a variable based on the field location and rock properties, an accurate estimation is only possible after evaluating the field properties. However, as a simple rule, well drilling cost can be estimated solely based on depth. The values obtained through this method, however, generally underestimate the actual cost of drilling and therefore having an additional cost allowance is recommended.

Costing of boilers and pumps is dependent on the technology used and, again, on the location of the field. However, using the costing correlation and factors given by (Sinnot, 2013), preliminary estimations can be made. Capital cost of pumps and boilers can be estimated based on volumetric and mass flowrate of injected fluid respectively and by:

$$CX_m = a + bZ^n \tag{15}$$

The value for a and b (constants) for each equipment can also be found in (Sinnot, 2013). Similar to drilling cost, the possibility of under estimation is high in this method and additional cost allowance should be considered. If storage facilities are not already available at the field, their cost can also be obtained with this method.

The next step is to obtain the financial potential of the thermal flooding methods based on the product sale. In order to do so, net present value (NPV) of the project should be calculated using the production profile obtained from RAVE. NPV, which can be integrated into RAVE, is calculated by:

$$NPV = \sum_{n=0}^{N} \frac{CF_n}{(1+r)^n} \tag{16}$$

The cash flow used in NPV calculation is computed by RAVE and is the difference between the expenditure and income of the project.

4.5 Pressure maintenance methods

The procedure applied to pressure maintenance simulation is similar to thermal flooding methods at all steps except for step 2. The main differences between the two methods are listed below.

- Step 1: No need for multiple runs at different bottomhole temperatures

- Step 2: Reservoir is assumed to be a tank with fixed volume. Therefore, in order to produce the amount of oil produced in step 1, the same amount of fluid should be injected into the reservoir. In other words, a simple mass balance procedure replaces the reservoir resistance procedure explained in thermal flooding section

- Step 3: Procedure similar to the hot water flooding path illustrated in Figure 12 with a possibility of different injected fluid

- Step 4: Same procedure without the need for heating equipment and possibility of different pressurising equipment in case of gas injection processes

5. CASE STUDY

In order to check the practicality of the proposed methodology and determine the shortcomings of it, a case study was considered based on the data from a generalised onshore heavy oil field. For instance, the effects of water cut profile, reservoir pressure, injection temperature and fuel type on economics and operability of the IOR methods were examined. The methods included in the case study are:

- Natural flow (base case)
- Steam flooding
- Hot water flooding
- Water flooding
- CO_2 injection (immiscible)

Natural flow was considered as the base case in order to measure the impact of IOR methods against it. CO_2 injection was chosen due to the fact that the intention towards utilisation of this method is increasing as the result of an increase in need for carbon capture. Finally water flooding, hot water flooding and steam flooding were selected in order to highlight the impact of stepwise heat addition on the oil production and process economics.

Figure 13 shows a simple schematic of the topside facilities required for each method. In all cases, it is assumed that injected fluid is available at the site and the only equipment required are those used to adjust pressure or temperature. In addition, since steam injection is considered, it was assumed that the field is located onshore. The arrangements of pumps and heat exchangers are not the same for hot water flooding and steam flooding. This difference is due to the fact that water pressure should be increased to boiler operating pressure prior to heating in steam flooding in order to eliminate the need for compression.

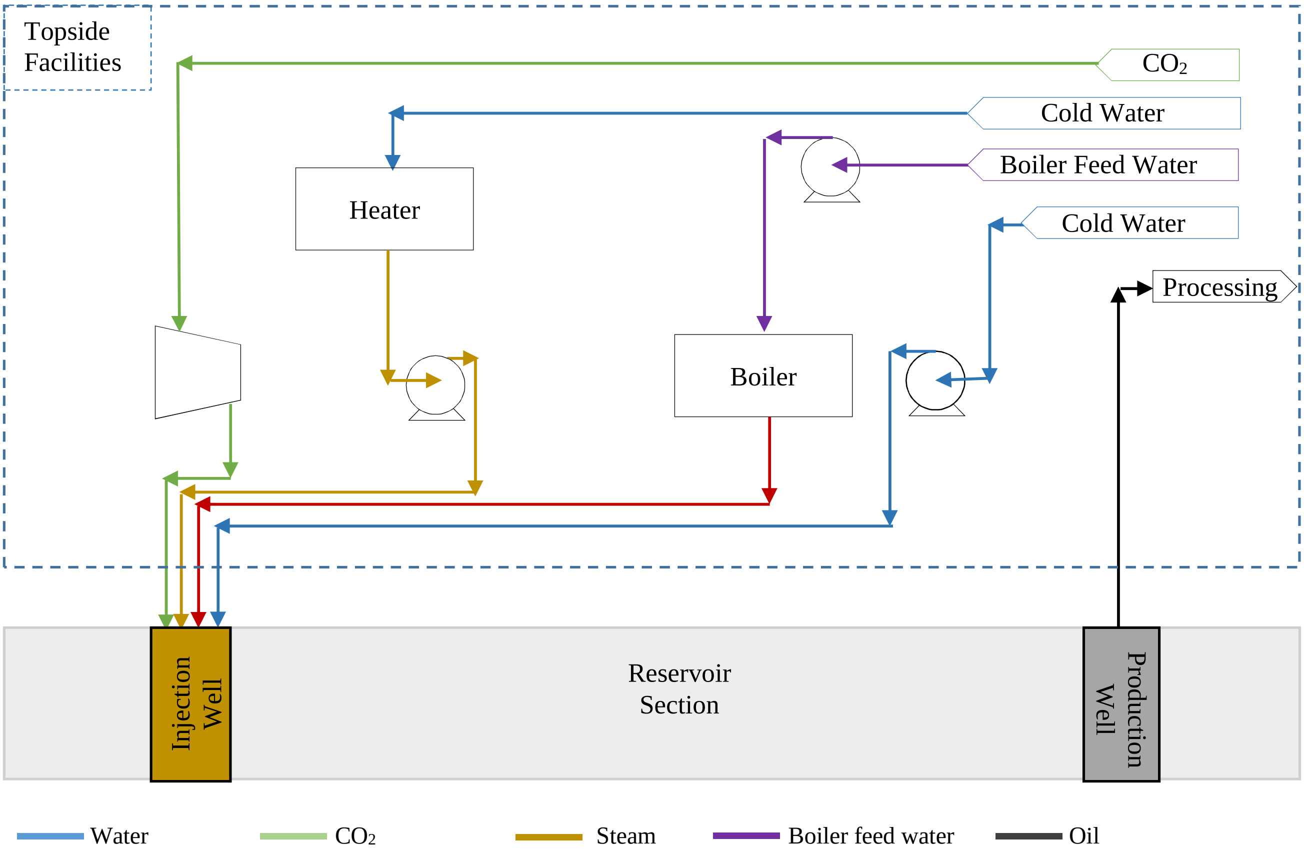


Fig. 13. Simple arrangement of selected IOR methods for use in case study (processes cannot be operated simultaneously)

5.1 Oil properties and PIPESIM input data

Both the injection and production systems in PIPESIM consist of one vertical well and one horizontal flowline (Figure 14).

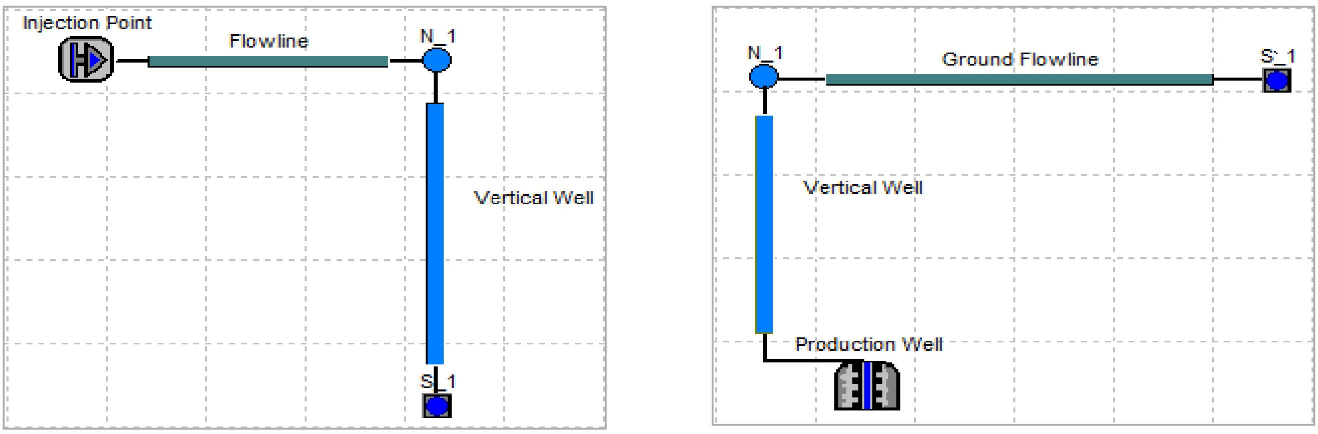


Fig. 14. Schematic of injection (left) and production (right) system in PIPESIM

Table 5 and 6 present the properties of the production and injection wells respectively. Since the main objective of this case study is comparison of different methods, these parameters should be kept constant for all of the methods.

Table 5: Case study input data for setting up the production well in PIPESIM

Property	**Unit**	**Value**
Productivity index	$STB.psi^{-1}$	5
Tubing U value	$BTU.ft^{-2}.h^{-1}$	2
Tubing depth	ft	1500
Tubing bottom ID	inch	4.87
Tubing casing ID	inch	8.681
Ambient temperature	ºC	5
Flowline length	ft	1000
Flowline inner diameter	inch	6
GOR (black oil model input)	$SCF.STB^{-1}$	40
Water cut (black oil model input)	%	50

Table 6: Case study input data for setting up the injection well in PIPESIM

Property	**Unit**	**Value**
Tubing U value	$BTU.ft^{-2}.h^{-1}$	0.2
Tubing depth	ft	1500
Tubing bottom ID	inch	3.958
Tubing casing ID	inch	8.681
Flowline length	ft	10
Flowline inner diameter	inch	12
Rate of undulation	-	10/1000

The reservoir conditions and oil properties (Table 7) were benchmarked against the boundary data presented in Table 4 and the results suggested that all of 4 methods considered in the case study alongside polymer flooding have the potential to be applied to this field.

Table 7: Properties of the heavy oil field considered in the case study

Property	**Unit**	**Value**
Reservoir temperature	ºC	20
Oil API gravity	º	12
Formation thickness	ft	30
Reservoir average porosity	-	0.25
Initial water saturation	-	0.2
Oil saturation	-	0.7
Specific heat of rock	$BTU.lb^{-1}.ºF^{-1}$	0.21
Specific heat of oil	$BTU.lb^{-1}.ºF^{-1}$	0.5
Rock grain density	lb/ft^3	167
Thermal conductivity rocks	$BTU.h^{-1}.ft^{-1}.ºF^{-1}$	1.5
Thermal diffusivity of rocks	$ft^3.h^{-1}$	0.0482
Residual oil saturation	-	0.1
Specific heat of water	$BTU.lb^{-1}.ºF^{-1}$	1
Water density	$lb.ft^{-3}$	62.32

The ranges variables required for generation of lift tables by PIPESIM are demonstrated in Table 8. These variables were all permeated against one another in order to generate the lift tables for use in RAVE. It should be noted that 300 psi was selected as the required topside pressure.

5.2 Lift tables

In order to facilitate simulation of the RAVE model, lift tables were generated for the flowline and tubing section of production well. In total, 5 different pairs of lift tables for 5 different reservoir bottomhole temperatures were produced. In the case of natural flow and pressure maintenance methods, lift tables produced at bottomhole temperature of 20°C (no added heat) were used while lift tables generated at bottomhole temperature of 50, 80, 110 and 140ºC were utilised for thermal flooding methods. Afterwards, 194 graphs analysing the effect of GOR, water cut, fluid flowrate and temperature on pressure drop were plotted. The first evaluated relationship was the effect of flowrate on pressure drop. As expected from Bernoulli equation, the higher the flowrate is, the higher the pressure drop will be.

Table 8: PIPESIM temperature/pressure profile input

Liquid Rate ($STB.d^{-1}$)	WC (%)	GOR ($SCF.STB^{-1}$)
10	0	1
100	20	40
1000	50	80
10000	80	120
20000	99	160

Afterwards, the effect of GOR variation on pressure drop was evaluated. It was observed that GOR and pressure drop are inversely proportional. In other words, as GOR increases, the pressure drop decreases. This phenomena was expected due to the fact that the oil density will be reduced as the gas content is increased. Consequently, the lighter fluid will result in lower frictional pressure losses.

Next, the effect of temperature on pressure loss was checked. First of all, it was observed that the impact of temperature on pressure loss becomes insignificant for cases when water cut is more than 50%. This behaviour was predictable since the water cut turning point was assumed to be 50% in PIPESIM production well model (Table 5). In other words, when the water cut is more than 50%, the fluid is treated as water rather than heavy oil.

One of the most significant behaviours observed in the lift tables was the reduced effect of temperature rise on decreasing the pressure drop. The pressure loss is reduced by 26.2% by the first temperature increase step while this change is reduced to 1.6% by the last step. This observation led to the decision of reducing the temperature change intervals. Therefore a new set of lift tables were generated at bottomhole temperatures of 30,40,50,70 and 90°C. The new temperature intervals give a closer pressure loss steps which in turn results in better observation of the impact of temperature on pressure loss and consequently fluid flowrate.

5.3 RAVE and M&L model

Similar to the PIPESIM model, the first step is to setup the physical RAVE model. Since the costing and heat loss calculation are carried out outside of RAVE, it was decided to eliminate the injection well from the physical model and add the CAPEX and OPEX of the injection well to the production well parameters. Figure 15 shows the final arrangement of the RAVE model utilised in the case study.

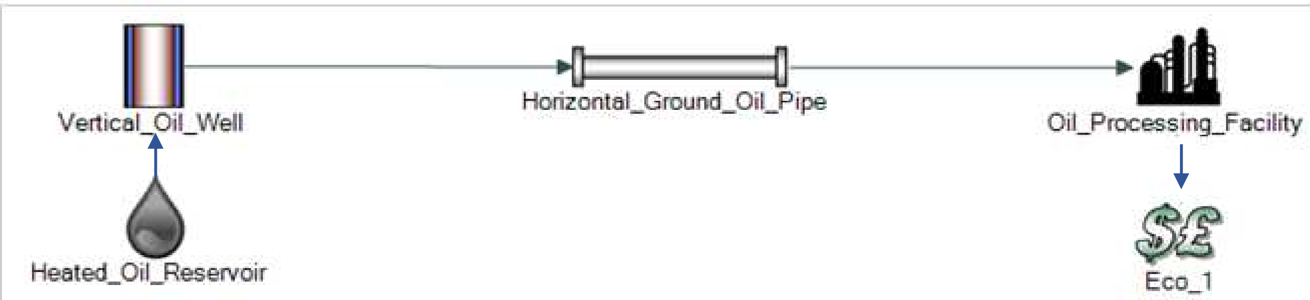


Fig. 15. RAVE physical arrangement used in the case study

Since there was no reservoir pressure data available for this case study, the first step towards running the RAVE model was assigning reservoir pressure. Since there are 3 different general oil production methods considered in this case study, it was decided to assign 3 different reservoir pressure profiles. In order to facilitate the natural flow of the oil, after considering the pressure drops in lift tables, it was decided to select 1500 psi as the initial reservoir pressure. It should be noted, however, that other RAVE simulations at reservoir pressures of 1000, 2000, 3500 and 5000 psi were also carried out for steam flooding and they validated this decision. In the case of natural flow, a constant monthly pressure drop of 10 psi was considered sufficient. On the other hand, for water flooding, hot water flooding and CO_2 injection, constant reservoir pressure was assumed. Despite the fact that steam flooding can increase reservoir pressure or sustain the reservoir pressure at the initial pressure conditions in some projects (Speight, 2009), slight and gradual pressure drop could occur due to steam condensation (Zhao, 2014). Therefore, it was decided to assume a constant monthly pressure drop of 3 psi in the reservoir.

The next step towards running the RAVE model was assigning a cumulative liquid flowrate profile. This objective was achieved through a trial and error procedure. In more detail, after obtaining the maximum cumulative flowrate, which belonged to the highest temperature run, it was divided into equivalent steps from the initiation of the project to the termination of it.

In order to include all the possible scenarios in the case of water cut, it was decided to evaluate the project based on three different well water cut profiles of downside (late), medium and upside (aggressive). This way, the worst case scenario of early water breakthrough and best case scenario of late water breakthrough can be benchmarked against each other. Figure 16 illustrated these 3 water cut profiles.

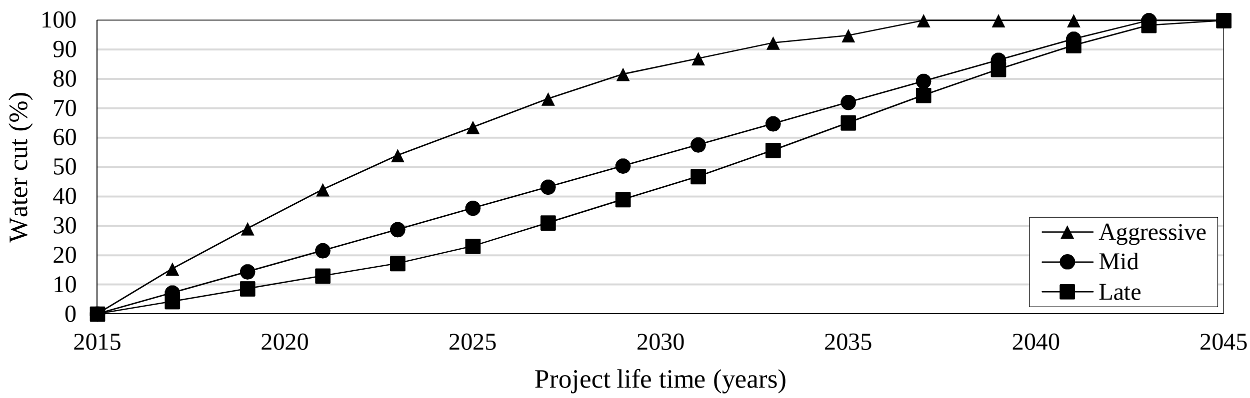


Fig. 16. Production well water cut profiles

In addition to entering the reservoir and well profile, RAVE requires some boundaries and limits. For instance, it was assumed that the liquid and gas capacity of the topside facilities are limited to 10000 barrels per day and 10^9 SCF per day respectively. In addition, it was assumed that all the methods will have the same abandonment cost of 5 million GDP. This assumption was made due to the fact that inaccuracies would occur in any attempt to estimate the costs in details during the early stages of the project.

After setting the physical model and entering the values for the base case (at bottomhole temperature of 20°C), other scenarios at different bottomhole temperatures, water cut profiles and flooding methods were added. This procedure resulted in an overall of 36 scenarios. The model was run and the maximum oil production rates were obtained. Figures 17 and 18 demonstrate the peak oil flowrate and maximum achievable cumulative oil flowrate (late water cut scenarios) for each method respectively. Since the only variable in the case of the peak oil is production well bottomhole temperature, Figure 17 is based on this parameter rather than specific methods.

As shown in Figure 17, the largest increase in daily oil production rate is from 20 to 30ºC. On the other hand, even by doubling the increase in step size, the production is only slightly increased by going from 70 to 90ºC.

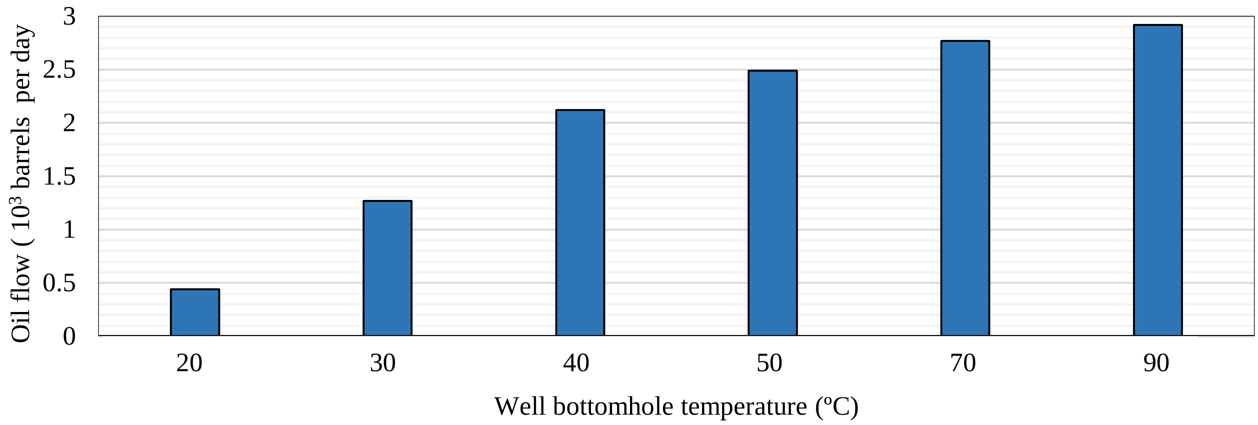


Fig.17. Maximum oil rate achievable at various production well bottomhole temperature

Despite operating at the same bottomhole temperature, hot water flooding has around 30% more production at all temperature intervals (Figure 18). This phenomena can be justified by the constant reservoir pressure assumption for hot water flooding and the decreasing reservoir pressure drop of steam flooding. Next the required steam and hot water were computed by M&L model and the required CO_2 and water were calculated by a mass balance assumption.

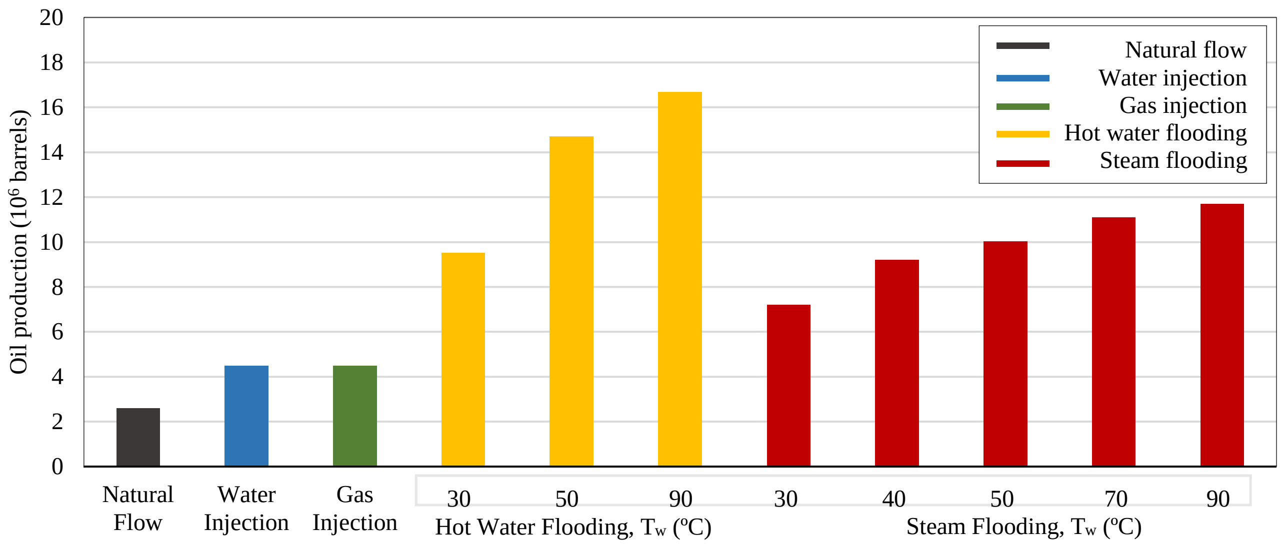


Fig. 18. Cumulative oil production in 30 years through different methods

The next step towards completing the case study and consequently comparing the suitability of each method was obtaining the cost of each method. The costing of thermal methods, as shown in Figure 13, is dependent on pumping and heating costs. Since the type of fuel used for heating is an important factor in operational cost of the heating processes, it was decided to evaluate all the thermal methods for three different types of fuel; natural gas, diesel and crude (heavy oil). This procedure increased the number of scenarios to a total of 81. Figures 19 and 20 illustrate the CAPEX and OPEX of the methods respectively. Since it was assumed that no extra assistance is needed in the case of natural flow, the OPEX of this method is set to zero and the CAPEX of it is equivalent to the cost of production and injection well drilling.

As shown in Figure 19, the highest capital investment belongs to CO_2 injection while the lowest one, as expected, be-longs to water flooding. In addition, since larger pumps and boiler are required as the injection temperature is in-creased, the CAPEX has a rising trend as the production bottomhole temperature is increased. Also, for the same bottomhole temperature, hot water flooding has a higher CAPEX. This is due to the fact more water and consequently larger heater and pumps are required for water flooding.

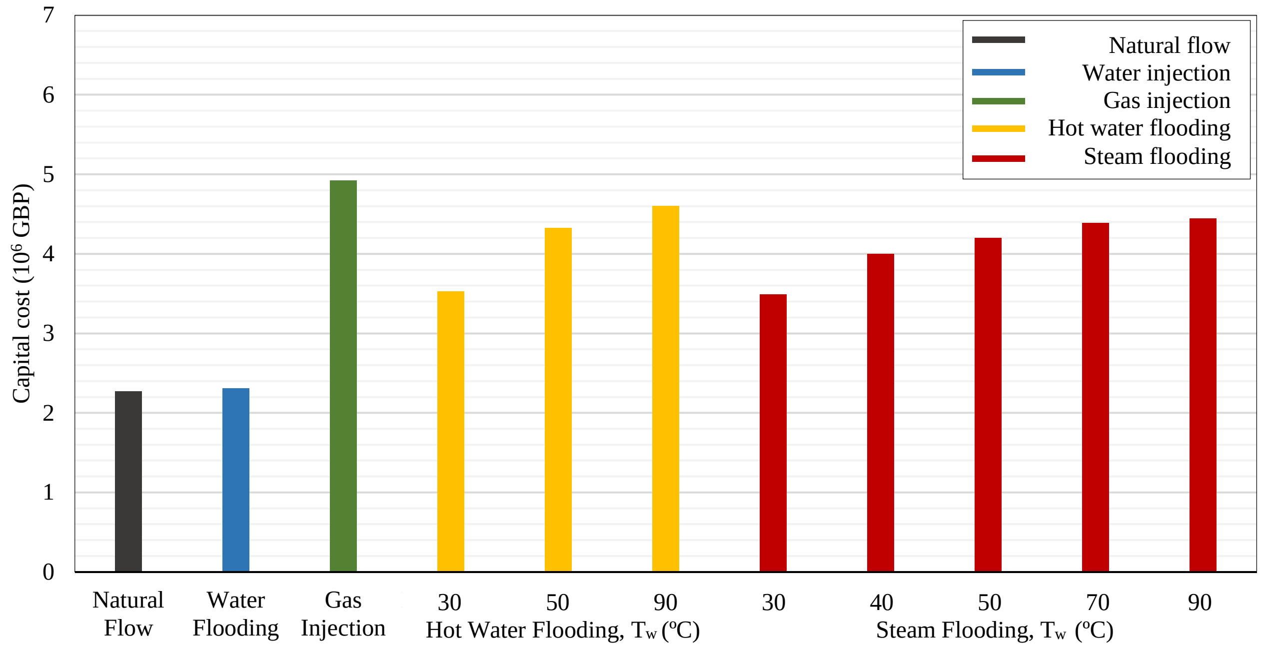


Fig. 19. Capital cost of the methods reviewed in the case study

In case of the OPEX of the methods, as illustrated in Figure 20, thermal methods are significantly more expensive. This trend is explained by the continuous thermal energy requirement of them. As opposed to the CAPEX of the methods, hot water flooding has a lower OPEX compared to steam flooding. This behaviour was expected due to the fact that in hot water

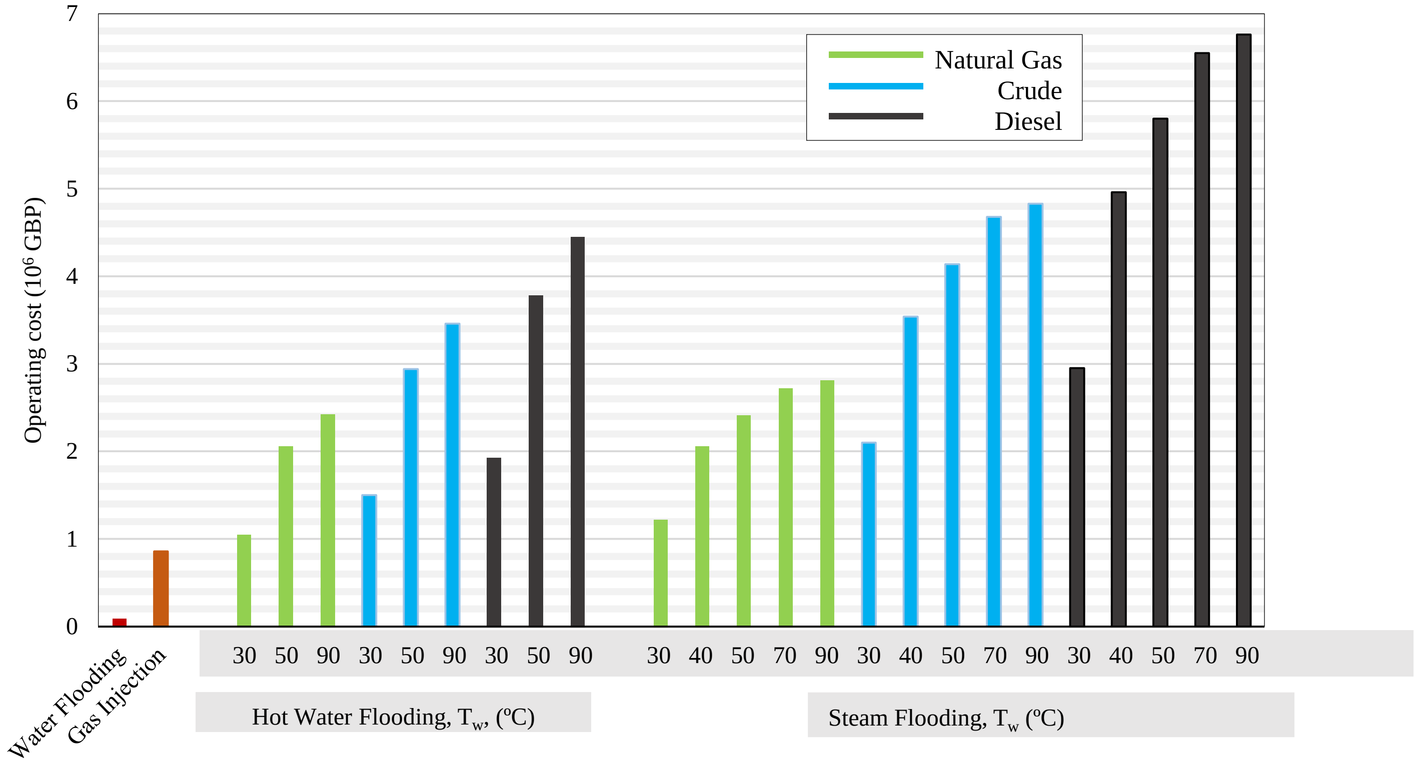


Fig. 20. OPEX of the oil extraction methods considered in the case study (including the fuel type effect; mid water cut profile)

flooding, the only thermal requirement is sensible heat while latent heat of evaporation should be supplied in addition to sensible heat in the case of steam flooding.

Another observable factor in Figure 20 is the effect of available fuel on the project economics. Usually, if natural gas is available, it is the preferred source of energy due to lower cost. This general rule can also be justified by this case study. However, natural gas is not always readily available in heavy oil projects due to the low GOR of the heavy oil reservoirs. Therefore another energy source should be used. It is suggested that it is more economically viable to burn some of the produced oil rather than purchase diesel if natural gas is not available even though this leads to lower oil revenue.

Despite the fact that information on production capacity and associated costs of the methods can be an indication of a methods suitability, only a combination of these two can facilitate the comparison of these methods and demonstrate the thorough effect of production variables such as water cut and temperature variation. Therefore, the NPV of each scenario was computed by RAVE after applying the OPEX and CAPEX values to it.

From theory, as water cut increases, the oil production rate decreases leading to a reduction in project NPV and consequently reduced profitability. However, the degree to which the water cut profile affects the NPV of different methods was not known. Therefore, graphs of scenarios in which all the conditions are identical except the water cut profile were plotted to observe the response of each method to water cut variation. Figure 21 illustrates that the NPV of the steam flooding can be

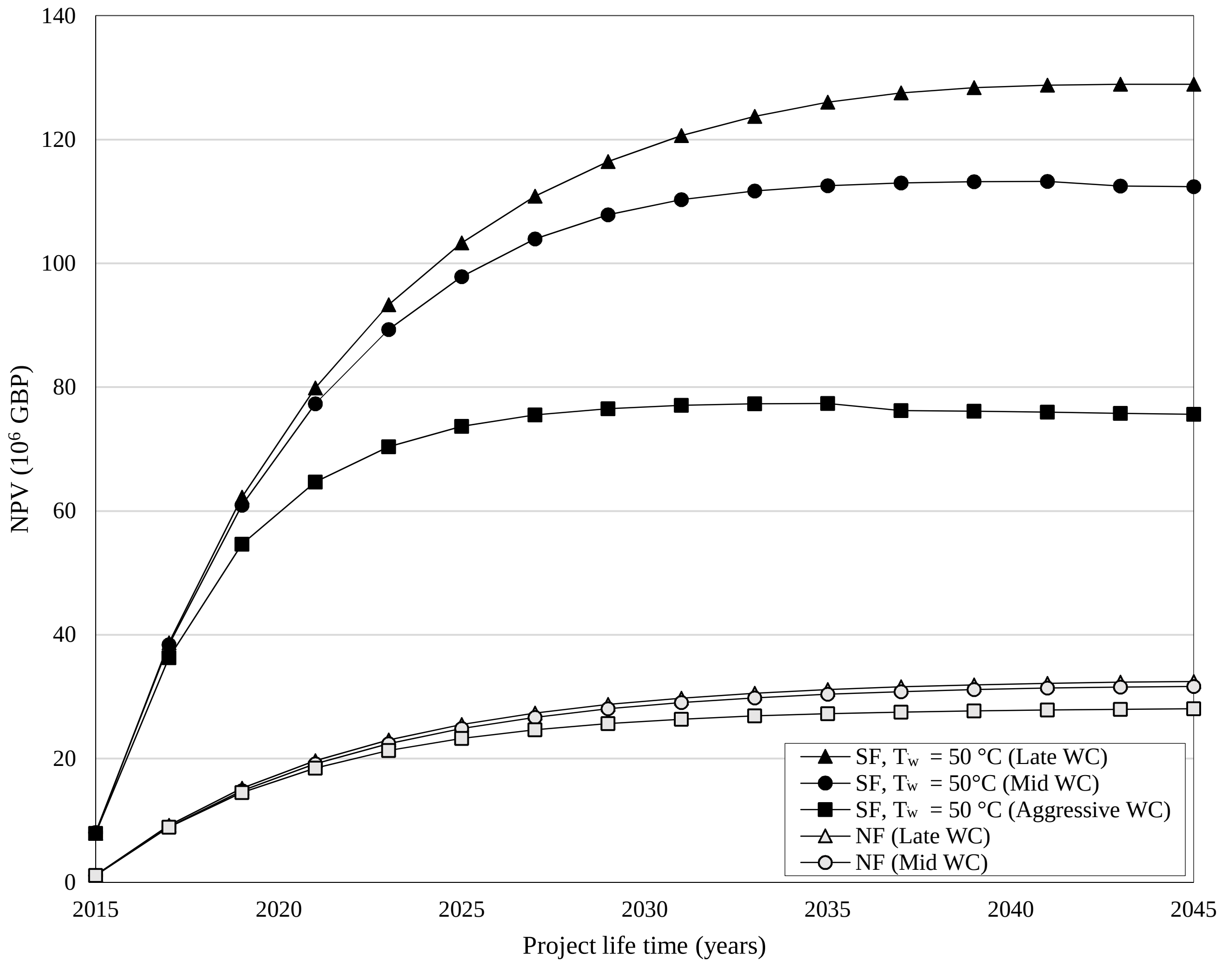


Fig. 21. Effect of water cut on project NPV for natural and steam flooding methods (based on natural gas as fuel)

increased by almost 40% by controlling the reservoir behaviour and consequently water production rate. Therefore, methods by which the water breakthrough is controlled should be considered and analysis should be carried out on their costs and benefits during steam flooding processes.

The effectiveness of cold methods was then compared with natural oil flow. For this, the data for all three water cut profiles of cold methods were utilised. As shown in Figure 22, CO_2 flooding has a lower NPV than natural flow except for the late water cut profile. This behaviour represents the current issue with heavy oil CO_2 flooding; the high cost of CO_2 and gas compression. However, it should be noted that in the case of CO_2 flooding, it was assumed that no miscibility takes place in the process (Al-Jarba, 2009). Therefore, in a more realistic reservoir simulation, the performance of CO_2 flooding might increase due to the slight increase in oil production caused by minor miscibility of CO_2 in the heavy oil.

In comparison to CO_2 injection, water flooding is expected to perform better than natural flow even with a more aggressive water cut. This superiority over natural flow is justifiable by the maintained reservoir pressure provided by water flooding. In comparison with CO_2 flooding, the better performance of water flooding can be explained by lower cost of water and pump compared to CO_2 and compressor respectively. Since water flooding has a higher NPV compared to natural flow, it was decided to compare it with thermal methods in order to verify whether application of thermal methods is justifiable or not. Due to the fact that presenting and comparing all the thermal methods scenarios were not practical, it was decided to select the scenarios which can be representative of all of the other scenarios. Therefore, it was decided to select the coolest and the warmest thermal methods at the medium water cut profile.

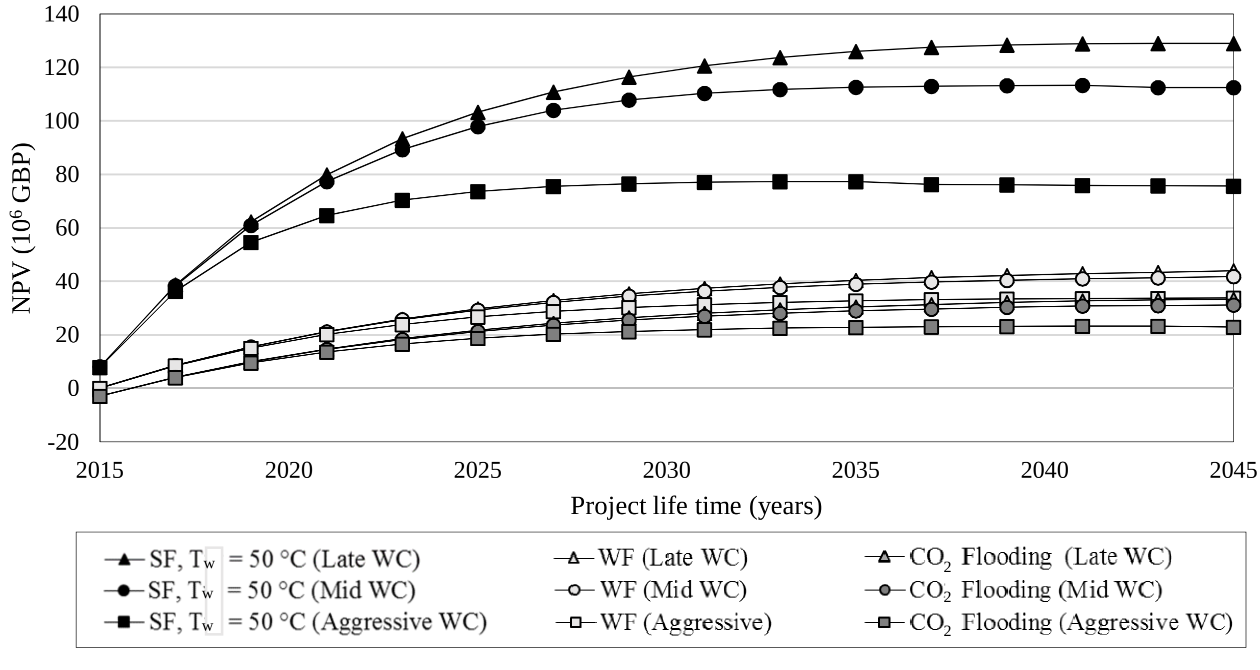


Fig. 22. NPV comparison of cold IOR methods reviewed in the case study (based on natural gas as the fuel)

As shown in Figure 23, all the thermal methods have higher NPVs compared to water flooding. This is the result of significantly higher oil flow rate in thermal methods compared to water flooding. However, it should be noted that this gap between thermal and cold methods might be much smaller during actual projects. This probability is due to the fact that the M&S model does not consider the initial stages of production when steam or hot water come into contact with cold heavy oil. During this omitted stage, the oil flowrate is insignificant while steam is injected at a constant rate. This mechanism can reduce the NPV of the project significantly

Another important observation is the higher NPV of hot water flooding than steam flooding. Since the API gravity of the oil was assumed to be 12°, from the literature, it was expected that steam flooding perform better than hot water flooding. There are two main explanations for this mismatch between literature and the result of this case study:

1. It was assumed that reservoir pressure profile has a decreasing slope. This assumption can hold untrue in most steam flooding projects

2. The effects of hot water flooding and steam flooding on reservoir behaviour are assumed to be the same in the M&L model which is not true. In reality, the heat transfer is more efficient from steam to oil rather than water to oil.

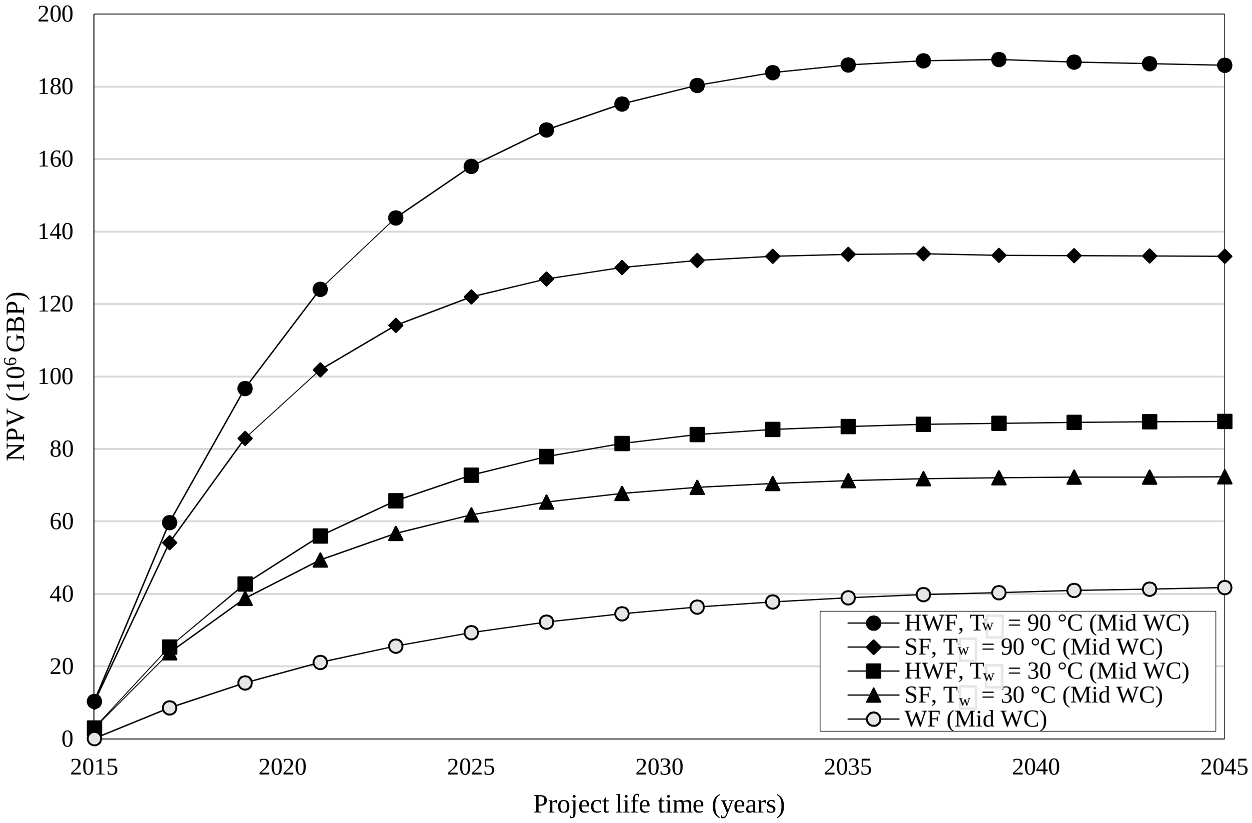


Fig. 23. NPV comparison of thermal methods and water flooding

Finally, the effect of water cut on the production period was reviewed. It was assumed that the field should be abandoned when the discounted cash flow of the project becomes negative. None of cold methods reached abandonment time during the 30 years of production. This observation is justifiable by the fact that for pressure maintenance methods constant reservoir pressure maintained oil flow while in natural flow, non-existence of OPEX made the process eventually cost free.

In the case of hot water flooding, for both of the bottomhole temperatures of 30ºC and 50ºC, abandonment time is reached only at aggressive water cut regardless of boiler fuel type. However, for bottomhole temperature of 90ºC, all of the scenarios have decreasing NPV at some point during the project life. For steam flooding, except the scenario for late water cut run at bottomhole temperature of 30ºC using natural gas as fuel, all scenarios should be abandoned during the project life. Figure 24 is a sample example of the correlations between fuel type and water cut on the project life and all the other scenarios follow the same trend.

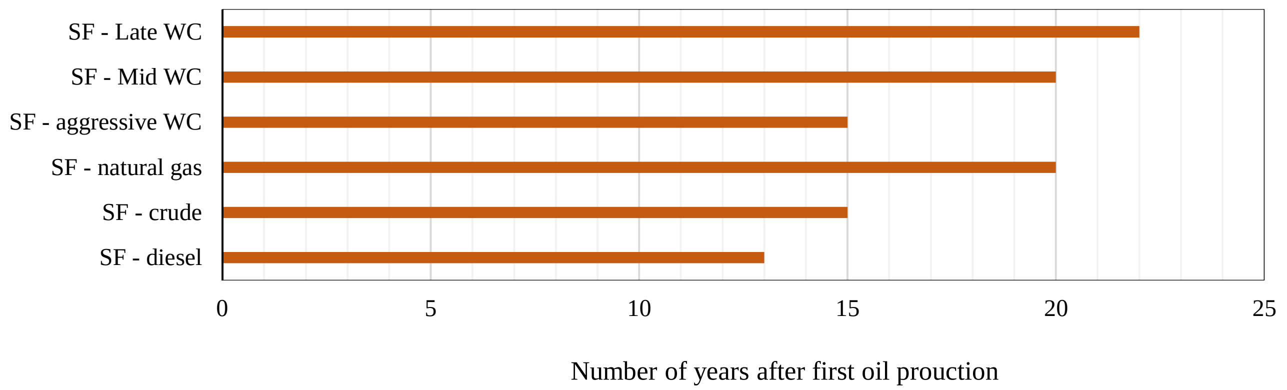


Fig.24. Effect of fuel and water cut on project life (sample example for steam flooding)

6. CONCLUSION

This paper has presented a database and worklow integration methodology based on two core software applications (PIPESIM and Excel) which are fundamental tools for any oil and gas field appraisal and development procedure. A step-by-step procedure on how to set up and connect the PIPESIM model with the Excel file for heavy oil production and fluid injection is presented; to the best of our knowledge, such a method has hitherto not been analysed in a dedicated publication. This procedure can serve as detailed guidance to software developers who are relatively new to oil and gas industry, in order to set up and evaluate the interoperability of common software tools which are broadly used or hydrocarbon field technology development projects. Also, it can quickly familiarise those readers who have programming expertise outside the oil and gas industry, with the basics of petroleum extraction methods and their relative suitability on the basis of the variable reservoir conditions.

Most of the behaviours observed in the case study results were in line with the theory and matched the expectations except for a few. The most noticeable unexpected behaviour of thermal flooding model was the dominance of hot water flooding over steam flooding. This observation would have been expected if the oil API gravity was high but for an API gravity of 12, steam flooding was expected to be the more viable option. This response highlighted two potential flaws in the modelling:

1. The assumption of the reservoir pressure profile was not realistic
2. The M&L model has limitations in modelling the reservoir mechanism accurately

In the case of cold methods, the most significant observation was superiority of natural flow and water flooding over CO_2 injection. Despite the fact that this behaviour was expected with regards to water flooding, CO_2 injection might behave better than natural flow if minor miscibility of CO_2 in water was considered.

In conclusion, the data presented in this paper can be used as a two layered preliminary screening model;

1. Initially, using the IOR application boundary conditions, the suitability of all the current heavy IOR methods is checked.
2. If the benchmarking process suggests that pressure maintenance or thermal flooding methods are suitable based on the reservoir conditions, the NPV of the process can be calculated based on the required oil production rate and required injection rate utilising RAVE, PIPESIM and the M&L model.

In both the thermal flooding and pressure maintenance models, the behaviour of the reservoir could be simulated more accurately if advanced simulators are available. For instance, in the case of the thermal flooding model, data from a reservoir simulator such as ECLIPSE can improve the accuracy of the model significantly. However, the procedure presented in this paper could be used effectively in order to evaluate the financial potentials of a heavy oil field rapidly and at minimum costs.

NOMENCLATURE

Symbol	Parameters
a	Costing constant
A	Swept reservoir area, ft^3
b	Costing constant
C	Heat capacity of the reservoir rock, $BTU.ft^{-3}.^oF^{-1}$
C_O	Specific heat capacity of oil, $BTU.lb^{-1}.^oF^{-1}$
CF	Cash flow, $
C_r	Specific heat capacity of rock, $BTU.lb^{-1}.^oF^{-1}$
C_w	Specific heat capacity of water, $BTU.lb^{-1}.^oF^{-1}$
CX_m	Capital cost of equipment, $
D	Thermal diffusivity of reservoir rock, $ft^3.h^{-1}$
H	Formation thickness, ft.
h_{hf}	Enthalpy of hot fluid, $BTU.lb^{-1}$
k	Thermal conductivity of rock, $BTU.\ ft^{-1}.h^{-1}.^oF^{-1}$
M_{hf}	Mass flowrate of hot fluid, $lb.h^{-1}$
P	Pressure, psi
Q	Thermal energy, $10^6.\ BTU.h^{-1}$
Q_L	Heat loss during production, %
r	Interest rate, %
S_O	Oil saturation, %
S_{Or}	Residual oil saturation, %
S_w	Initial water saturation, %
t	Time, h
T_{amb}	Ambient temperature, ºF
T_{hf}	Temperature of hot fluid, ºF
T_r	Reservoir temperature, ºF
T_w	Production well bottomhole temperature, ºC
x	Dimensionless time
Z	Size parameter
ΔT	Temperature difference, ºF
ϕ	Porosity, %
ρ_o	Oil density, $lb.ft^{-3}$
ρ_r	Reservoir rock density, $lb.ft^{-3}$
ρ_w	Water density, $lb.ft^{-3}$
μ	Viscosity, cP

ABBREVIATIONS

AMPCP	All-Metal Progressive Cavity Pumps
API	American Petroleum Institute
ASP	Alkali-Surfactant-Polymer Flooding

BHP	Bottom Hole Pressure
BPD	Barrels Per Day
CAPEX	Capital Expenditure
CHOPS	Cold Heavy Oil Production with Sand
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
ESP	Electrical Submersible Pump
GOR	Gas to Oil Ratio
HASD	Horizontal Alternating Steam Drive
HSP	Hydraulic Submersible Pump
HWF	Hot Water Flooding
IAM	Integrated Asset Model
IFT	Interfacial Tension
IM CO_2	Immiscible Carbon Dioxide Flooding
IM HC	Immiscible Hydrocarbon Flooding
IM N_2	Immiscible Nitrogen Flooding
IM WAG	Immiscible Water Alternating Hydrocarbon Gas Flooding
IOR	Improved Oil Recovery
M HC	Miscible Hydrocarbon Flooding
Mid	Medium
M&L	Marx and Langenheim model
M&S	Myhill and Stegemeier model
M&V	Mandl and Volek model
NPV	Net Present Value
OPEX	Operating Expenditure
PCP	Progressive Cavity Pump
PVT	Pressure-Volume-Temperature
SAGD	Steam Assisted Gravity Drainage
SCF	Standard Cubic Feet
SF	Steam Flooding
SRP	Sucker Rod Pump
STB	Standard Barrel
RAVE	Risk And Value Engineering
THAI	Toe-to-Heel Air Injection
WC	Water Cut
WF	Water Flooding
WAG	Water Alternating Gas Flooding

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